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COAL GASIFICATION: OPPORTUNITIES AND CHALLENGES

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED TENTH CONGRESS

FIRST SESSION

TO

ADDRESS OPPORTUNITIES AND CHALLENGES ASSOCIATED WITH COAL GASIFICATION, INCLUDING COAL-TO-LIQUIDS AND INDUSTRIAL GASIFICATION

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COAL GASIFICATION: OPPORTUNITIES AND CHALLENGES

THURSDAY, MAY 24, 2007

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 9:35 a.m., in room SD–366, Dirksen Senate Office Building, Hon. Jeff Bingaman, chairman, presiding.

OPENING STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

The CHAIRMAN. Why don't we go ahead and get started?

Thank you all for coming today. We're here to talk about coal gasification technology and how it can be used to meet our needs, both for energy security and reducing our contribution to global warming. Although the fundamental technology we're talking about today has been around for many decades, relatively recent developments in the technology point to a pathway that may allow us to use the abundant coal reserves that we have in a way that's responsible, for future generations. Our testimony today will help develop the policies that will guide that development in the right direction.

Let me first indicate that this hearing will not be the last that we have on this subject, or the last hearing or workshop that we have on this subject. We will be holding a longer, more in-depth hearing or workshop on coal gasification, including coal-to-liquids, sometime in the next month or so. Senators Tester, Corker, Dorgan, Salazar, and Conrad, have all requested that we do so. I believe Senator Bunning has joined in that. Coal-to-liquids, in particular, has received great attention lately, due to the strong advocacy of various people on this committee, and also, Montana's Governor, Brian Schweitzer. I believe that we have much more to explore in that area, and in the related areas of industrial use of coal. So, I hope that today's hearing will be a good first step in assessing the future uses of clean coal technologies.

We're entering a challenging time for energy in the United States. While our fuel prices are going up, we're becoming increasingly reliant on unstable, or unsavory, regimes for that fuel. We're facing an increasingly urgent need to begin addressing the real problems of global warming. I think we've reached a point of consensus around this place on those issues, and that's a positive development.

As the stabilization wedges that were developed at Princeton, and are going to be referenced by at least some of our witnesses today, make clear, we need to make advances on many fronts at the same time if we're to deal with the issue of greenhouse gas emissions. No one technology or policy will suffice. It's very difficult to be sure which technology is going to be the most important for the future.

The investments that we're going to be making in coming years are significant. I think we're well advised to be careful to make sure we don't make our challenges greater in other areas in trying to address our fuel needs.

I don't think anyone here would seriously dispute that coal is an important part of our fuel mix for the foreseeable future. Our domestic reserves are abundant. The price spread between coal and other fossil fuels is likely to make coal a very attractive option for a long time.

However, the capital associated with coal facilities, and particularly coal gasification facilities, is very high, often in the range of $3 or $4 billion, or even more. Their expected useful life is substantially more than 20 years. As a result, if we make a mistake and encourage the development of plants that we later find to be incompatible with our need to reduce greenhouse gas emissions, this could prove to be a costly mistake. For that reason, it makes sense for us to be careful to structure incentives so that we don't lose sight of where we need to be in the years ahead.

I believe we need to try to get a greenhouse gas emissions framework in place as soon as possible. But, if that does not happen this year, I think most would agree that it is going to happen sometime in the relatively near future. The price signals are not in place today to force deployment of the cleanest technologies that we have available. That does not mean commercial development and demonstration of those technologies should have to wait.

The best way to avoid economic shocks down the road is to lay the foundations today for the clean technologies that we will be deploying tomorrow throughout forward-looking, technology-forcing incentives.

So, we have some very good witnesses today. I look forward to hearing from them. But, before introducing them, let me call on Senator Domenici for any comments he has.

[The prepared statement of Sentor Salazar follows:]

PREPARED STATEMENT OF HON. KEN SALAZAR, U.S. SENATOR FROM COLORADO

I want to thank Chairman Bingaman and Ranking Member Domenici for holding today's hearing on coal gasification, and efforts to convert coal to liquid fuels. During the Energy and Natural Resources Committee mark-up of the Energy Savings Act of 2007, we asked Chairman Bingaman and Ranking Member Domenici to hold a hearing on issues related to converting coal to liquid fuels. I appreciate the efforts of Chairman Bingaman, Ranking Member Domenici, and the committee staff that went into putting this hearing together so quickly.

My home state of Colorado is endowed with many natural resources, including vast coal resources. In Colorado, 71% of the electricity we produce is generated with coal. Colorado consumed 18.9 million tons of coal in 2004, generating 37.5 million megawatts of electricity. Most of this coal comes from Colorado, but some of it is from Wyoming.

Coal is our most abundant domestic energy source. It provides more than 50% of our nation's electricity needs, and America has enough coal to last more than 200 years. Unfortunately, CO_2 pollution from coal combustion is a main cause of global warming, which threatens my state's water resources, our economy, and our quality of life.

Fortunately, there seems to be more than one way to reconcile coal use with protecting our climate, through new low-carbon technologies such as Integrated Gasification Combined Cycle (IGCC), oxy-coal combustion, coal gasification and ultra-supercritical generation. In addition, advancements in capturing carbon and safely sequestering it underground will allow our country to use coal, and at the same time reduce CO_2 emissions. I am proud of the work this Committee did in the Energy Savings Act of 2007 to promote research, development and deployment of carbon capture and sequestration technologies, and to do an assessment of our nation's carbon storage capacity. What we learn from the national assessment may be valuable in determining optimal locations to place coal-to-liquid plants in order for them to be near areas where the CO_2 emissions can be safely sequestered.

Advances in technology indicate that a coal-to-liquid plant using combined cycle technology, carbon capture and storage, and biomass as part of the fuel source can result in far lower greenhouse gas emissions. It is my understanding that some coal-to-liquid processes can use up to 30% biomass in the feedstock, which reduces the CO_2 emissions from the process. The use of a renewable fuel like biomass in these plants presents a great opportunity to allow for an expanded use of coal without adding to global warming.

Thank you Chairman Bingaman and Ranking Member Domenici for holding today's hearing so that we can learn more about how our country's greatest fossil fuel resource can be used to expand the production of domestic fuels.

STATEMENT OF HON. PETE V. DOMENICI, U.S. SENATOR FROM NEW MEXICO

Senator DOMENICI. Thank you very much, Mr. Chairman.

I apologize for being a couple of minutes late, but it was impossible to get out of a traffic jam and get here any sooner. But I want to thank you, Senator, for holding this hearing.

This hearing is not new to the committee. We've had several hearings and conferences on this issue since 2005. All of our sources of energy are going to be needed to help meet our Nation's energy needs, and strengthen our energy security. We will need wind, solar, geothermal, and all types of biomass. We will need nuclear energy, and, yes, we will need America's most abundant source of energy: coal. I have said, on numerous occasions, that the Nation will be using greater amounts of coal to meet our future energy demands. Today, coal-fired power plants account for 50 percent of electricity generation in the United States. EIA estimated that by 2030 this percentage will be 57 percent, up by a full 7 points. Today, we look at the usefulness of coal as a source of transportation fuel. I have many questions regarding the environmental issues surrounding this; however, I hope people will look at coal-to-liquids and ask, "What are the challenges we must face?" instead of asking how these challenges can be used to scare people. This issue deserves a full and fair debate, and we must consider our Nation's energy security.

The rest of the world is competing against us for every drop of available oil and natural gas, and that competition will become more intense, not less. These nations—often with massive State-owned entities—will be competing against us to find new energy sources and intellectual resources to find, develop, and implement these new technologies. We must lead in developing clean coal technology, renewable technologies, and carbon sequestration technologies. The decision that this Congress will be making this year will set the American energy course for a number of generations to come.

Coal is a source that we have an abundance of, and if we develop it wisely and lead the march to new clean coal, we will be, without any question, leading the parade of technologies to coal technology. It will give us economic potential to compete with the world's emerging economies.

Here is what we know about coal-to-liquids: other countries, like South Africa, have been converting coal into transportation fuels through the Fischer-Tropsch process full-time for some time. This is not a new technology. It has been around since prior to the second World War. A number of these processes to convert coal to transportation fuel have been invented and are being tested and implemented in various parts of the world, including China. Currently, China is constructing an 800,000–barrel-per-day coal-to-liquid facility, and the Chinese government proposes to build as much as 1 million barrels of daily coal-to-liquid capacity by 2020. Though there are many challenges to this, we should try to meet them, not run away from them. The National Energy Technology Laboratory recently released a report that indicates that the Fischer-Tropsch's liquids facility, with carbon dioxide captured, is both technically and economically feasible. Many agree that technologies to remove carbon dioxide, and then sequester that carbon dioxide, exist, but large-scale tests of carbon dioxide sequestration must be completed.

Some of our witnesses today will discuss ways to integrate biomass and coal-to-liquid technologies that would be nearly carbon-neutral.

The United States Air Force is currently working with the National Energy Technology Laboratory and others to develop a domestically produced coal-based aviation fuel to supply all of the Air Force's aviation fuel needs. It would be cleaner burning, and it would also be domestically secure.

I look forward to hearing from our witnesses today, and I'm excited by those who suggest that we can integrate coal-to-liquid, gasification, and biomass, and produce transportation fuels in an environmentally safe manner.

With that, I will close, and I look forward to the testimony today.

Thank you very much, Mr. Chairman.

The CHAIRMAN. Thank you very much.

Senator Dorgan indicated he'd like to make a short statement, and then, if any of the other members would, we'll do that before we introduce the witnesses.

Senator Dorgan.

STATEMENT OF HON. BYRON L. DORGAN, U.S. SENATOR FROM NORTH DAKOTA

Senator DORGAN. Mr. Chairman, not so much a statement as a comment: I am told I'm going to be called to offer an amendment on the floor on the temporary worker provision in a few short minutes, and it'll be an amendment to sunset that provision. So, before I get called away, I did want to make one point.

Back in the 1970's, we began a movement toward coal gasification and a very big project. One was built on the prairies of North Dakota, called the Great Plains Coal Gasification Plant. Today, as we speak, it will be producing synthetic natural gas from lignite coal. It is a technological marvel. It exceeds everybody's expectation, produces not only synthetic gas, but also chemical by-products. At the same time that we're doing that, we built a pipeline to transport the CO_2 into Canada, and so the CO_2 from this coal gasification plant—as we produce synthetic gas from lignite coal—the CO_2 goes to Alberta, Canada, where it is invested into marginal oil wells to increase the productivity of oil recovery in Canada. It is, I think, the largest CO_2 capture and beneficial use in the world.

I just wanted to make that point, because the Fischer-Tropsch process, and associated processes—much of this is not particularly new. We know we can do this. We have carbon-capture issues, but we're showing, in North Dakota, with the largest example of that in the world, that we can do that, as well. So, I just wanted to make that point, in the event I get called away for my amendment, I wanted that to be understood, that this is working in our country, and we can do much, much more of it.

[The prepared statement of Senator Dorgan follows:]

PREPARED STATEMENT OF HON. SENATOR BYRON DORGAN, U.S. SENATOR FROM NORTH DAKOTA

- We all recognize that important energy legislation will be coming to the floor of the Senate in early June. The Energy and Natural Resources Committee has worked in a bipartisan way on a number of bills and has proven to be very productive.
- During this time of high energy prices, U. S. dependence on foreign sources of energy (particularly oil and natural gas), our need for more renewable and alternative energy, and our need to address climate change, all provide a clear signal that more must be done.
- Coal is our most abundant, most secure, and lowest cost American energy resource. Coal is a major base load resource for power generation, and has to play a significant role in our energy mix.
- We have the world's largest coal reserves, with more than 275 billion tons (250 years supply at current usage rates) and we are the second largest consumer with over 1 billion tones per year.
- Lignite produces about 8% of our nation's coal needs and is vital to North Dakota since we have about 800 years worth of it in North Dakota.
- We can and should find new and different ways to use coal.
- Opportunities for coal use in the production of hydrogen, chemicals, fertilizer, and liquid fuels must be explored.
- I want to look at all of these options.

ENERGY SECURITY AND CLIMATE CHANGE

- We have come to a new intersection of energy policy and climate change, and there is an opportunity.
- The debate over climate change science has ended, and many of my colleagues have ideas and proposals to curb emissions.
- I believe there has been an attitude shift in the country recognizing the potential impacts of climate change, and we need to address climate change legislation in a thoughtful and comprehensive manner.
- Curbing carbon emissions is a long-term issue, but we have commercially ready technologies and opportunities such as enhanced oil and gas recovery and recovery of coal bed methane.
- Experts estimate that the U.S. has over 40 years of carbon dioxide storage capacity in our oil and gas fields, and the use of the carbon dioxide in this way could more than double our domestic oil and gas production and reserve base. This would enhance our energy security.
- Another 35 years of carbon dioxide storage capacity can be placed in un-mineable coal seams to possibly yield more natural gas.
- The long-term solution is storage in deep saline formations where we have the capacity to store hundreds of years of carbon dioxide.

- In order to unlock coal's potential, we need to do more than offer half-baked ideas.
- I had several concerns with the original Thomas/Bunning approach. It was very late in coming and had not been fully vetted.
- We need to require carbon capture and storage for these projects, but the Thomas approach only said that it was an option.
- If we don't find ways to incorporate carbon capture and storage then the total CO_2 emissions from coal-to-liquids is almost twice that of petroleum today.
- The Thomas/Bunning approach had set a standard for coal fuels at 21 billion gallons by 2022. But we still don't know where that came from, what it is based on, or if that is an achieveable figure.
- Our primary need is to focus on the right incentives to work with public funds to develop a core number of these facilities (like 4-5) with carbon capture so that they become viable to investors.
- There is a pathway forward. I want to work with others on the Energy Committee to find a way to make these happen.
- I look forward to the testimony and discussion with our panel of witnesses.

Senator BUNNING. Just very short.

The CHAIRMAN. Yes. Senator Bunning.

STATEMENT OF HON. JIM BUNNING, U.S. SENATOR FROM KENTUCKY

Senator BUNNING. I really want to thank you, Mr. Chairman and Senator Domenici, for following up and having this hearing, and more hearings in relationship, so that we can put the record straight on the use of coal-to-liquids or coal gasification, carbon capture, carbon sequestration, the cleanness of which it burns—the fuel, I'm speaking about and the Air Force's direct interest in a domestic-based fuel. And I thank you, from the bottom of my heart, for holding this hearing.

The CHAIRMAN. Great.

Senator Tester, do you want to make any statement, or Senator Corker, either one?

[No response.]

The CHAIRMAN. OK, I'll introduce three of the witnesses, and then call on Senator Corker to introduce the other two that are from his State of Tennessee.

The three that I'll introduce are: first, Dr. Antonia Herzog, who is the staff scientist with the Climate Center, the Natural Resources Defense Council, here in Washington. Thank you for being here. James Bartis is here, who is a senior policy researcher with RAND Corporation, here in Arlington, Virginia. Thank you for being here. Dr. Jay Ratafia-Brown is a senior engineer and supervisor with SAIC—Energy Solutions Group, in McLean, Virginia.

Senator Corker, did you want to introduce the other two witnesses from your home State?

Senator CORKER. I'd be delighted to.

I want to thank you, with the other Senators, for having these hearings. I know we've had numerous hearings in the past, along with the Finance Committee. I, too, want to thank you for following through and having these hearings again. I'm thrilled with the resources that we have in our own State as it relates to conquering these types of issues, and dealing with them, which makes me even more interested, obviously, in these types of technologies.

I'm really pleased that today we have two great Tennesseans. Bill Fulkerson is a senior fellow at the Institute for a Secure and

Sustainable Environment at the University of Tennessee, my alma mater. Before he joined the Institute, he was for 32 years at Oak Ridge Laboratory, a leader in helping us develop energy security here in our country. After that, he chaired the Department of Energy Laboratory R&D Working Group, and he's worked with an organization of R&D managers from 14 laboratories, working on energy issues. He drove up from Tennessee. He's driving back after these hearings. We thank him for being here.

David Denton is also from Tennessee. Eastman Chemical, since 1983, has been utilizing these technologies in a way that has led industry throughout America. In many ways, they are my inspiration, if you will, as it relates to this type of technology. David certainly is very highly involved in that, searching for new customers, if you will, in this particular technology. I welcome both of them here.

Thank you very much.

The CHAIRMAN. Thank you.

Thank you all for being here. Why don't we just start with Dr. Herzog. Why don't you go ahead. If each of you will take 5 to 6 minutes, and summarize the main points you'd like us to understand, we will include your full statement in the record.

Go right ahead.

STATEMENT OF ANTONIA HERZOG, STAFF SCIENTIST, CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL

Ms.HERZOG. Thank you very much. Thank you for this opportunity to testify today on the subject of coal gasification technology and its challenges and environmental impacts.

I'm staff scientist in the Climate Center at NRDC, a national nonprofit organization of scientists, lawyers dedicated to protecting public health and the environment.

I'd like to start by taking a broader perspective and considering the primary motivation for pursuing coal gasification technology. They are: its potential to reduce our dependence on foreign energy sources and reduce our CO_2 emissions from conventional coal use.

The first issue is tied to both national security concerns and the impact that several years of volatile and high natural-gas and oil prices have had on our businesses and consumers. The second is the result of the urgent need to turn the tide on global warming.

To the first motivation, coal has the advantages of being a cheap, abundant, and domestic resource, compared with oil and natural gas, and the process of coal gasification can produce substitutes for both of these.

To the second, coal gasification allows for more efficient, cost-effective capture of CO_2 from coal, which, if the CO_2 is then permanently disposed of, can provide a lower carbon energy source than conventional coal use. Any use of coal gasification must meet both these needs adequately. Furthermore, I have to add that there are many disadvantages of coal, beyond its CO_2 emissions, which simply cannot be ignored. From underground mining accidents and mountaintop-removal mining to air emissions of acidic and toxic pollution, from coal combustion, to water pollution, from coal mining and combustion rates, the conventional coal fuel cycle is among the most environmentally destructive activities on Earth, and we simply cannot forget this. This is why we believe, at NRDC, we must first turn to energy efficiency and renewable energy. Energy efficiency remains the cheapest, cleanest, and fastest way to meet our environmental challenges and energy needs, while renewable energy is the fastest growing supply option today.

Only then should we consider turning to methods that can potentially make coal more compatible with protecting health and the environment, and reducing our dependence on foreign energy sources. With the right standards and incentives, we can fundamentally transform the way coal is produced and used in the United States and around the world.

Congress is now considering proposals to promote coal gasification technologies with the goals of replacing natural gas, oil, and conventional coal combustion for electricity. These proposals can not only be evaluated in terms of our energy security concerns, but must also be evaluated in the context of the compelling need to reduce global warming emissions steadily, significantly, starting now, and proceeding along a declining pathway throughout the century.

My specialty is global warming, and so that's what I will focus on here. This is not in any way to downplay the other land, air, and water impacts, which are equally relevant and concerning to us.

To avoid catastrophic global warming, the United States and other nations will need to deploy energy resources that result in much lower releases of CO_2 than today's use of oil, gas, and coal. In short, we need to start now, and a slow start would mean a crash finish if we delayed starting soon. If we wait too long to deploy low-carbon technologies, then we would need to deploy them much faster than any conventional technology that has been deployed in recent decades. In addition, the effort would require prematurely retiring billions of dollars in capital stocks that will be built or bought online during the next 10 to 20 years, in the absence of appropriate CO_2 limits.

For the electricity sector, we believe that coal gasification technologies could play a significant role. More than 90 percent of the U.S. coal supply is used to generate electricity currently, and a little over half of the U.S. electricity supply is generated——

Senator DOMENICI. Senator Bingaman—excuse me—could we ask the witness where her testimony is? Where is she testifying from?

The CHAIRMAN. You're giving us a summary of the testimony you submitted to the committee, is that correct?

Ms. HERZOG. Yes. That's right.

The CHAIRMAN. I think that—the testimony she gave us is right here in your book. It should be.

Senator DOMENICI. Right.

The CHAIRMAN. But she's just—yes—and she's just summarizing it for us.

Senator DOMENICI. OK. I couldn't find a summary. The summary is not in here.

Ms. HERZOG. It isn't. I apologize.

Senator DOMENICI. That's fine.

Ms. HERZOG. OK.

Senator DOMENICI. I'll keep looking, and you'll be finished, and I'll still be looking.

Ms. HERZOG. Right, right.

[Laughter.]

Ms. HERZOG. Well, I'll certainly supply my summary afterwards. I admit to having worked on it last night.

Anyway, continuing, we do believe that you can use coal gasification to generate electricity, replacing conventional coal combustion, capturing 85 to 90 percent of the carbon, disposing of it permanently in geologic reservoirs, and this technology can be consistent with reducing our global warming emissions for the long term.

Now moving on to liquid fuels. We do not believe this happens to be the case for liquid fuels produced using coal gasification currently. To assess the global warming implications of a large coal-to-liquids program, we need to examine the total life cycle or well-to-wheel emissions of these fuels. Coal contains about 20 percent more carbon per unit of energy, compared to petroleum. When the coal is converted to liquid fuels, two streams of CO_2 are produced, one at the coal-to-liquids production plant, and the second from the vehicles when they burn the fuel. The unavoidable fact is that liquid fuel from coal contains the same amount of carbon as a gallon of gasoline or diesel made from crude. Thus, the potential for achieving significant CO_2 emission reductions compared to crude is limited.

Based on our analysis, that of EPA and Argonne National Lab, the total well-to-wheel CO_2 emissions from liquid coal plants is twice as high as crude oil if the CO_2 is released to the atmosphere. Obviously, introducing new fuel with twice the CO_2 emissions is simply not compatible with addressing global warming. Even if the CO_2 from the coal-to-liquids plants is captured, the well-to-wheels CO_2 emissions would still be higher than today's crude oil system, and it is not clear how efficiently and effectively we can capture that CO_2 in the production process.

Using coal to produce a significant amount of liquid for transportation fuels, we do not believe is compatible for our need to develop a low-CO_2-emitting transportation sector.

Let me just give a quick example of some of the problems. It's half of the alternative fuels——

The CHAIRMAN. Could you summarize your——

Ms. HERZOG. Finish up?

The CHAIRMAN. Yes, if you could——

Ms. HERZOG. OK.

The CHAIRMAN [continuing]. That would be great, too.

Ms. HERZOG. I'm going to give you one example here.

The CHAIRMAN. OK.

Ms. HERZOG. What is the best use of coal for the transportation sector? There are better paths, we believe, to take using coal. A ton of coal used in a power plant employing carbon capture and disposal to generate electricity for a plug-in hybrid vehicle will displace more than twice as much oil as using the same coal to make liquid fuel in a plant that also uses carbon capture and disposal.

Second, a hybrid vehicle running on liquid coal will emit ten times as much carbon dioxide per mile as that plug-in hybrid vehicle running on electricity made from coal using carbon capture and disposal.

So, I'll leave that thought in mind as to which is the best path to take for coal gasification technology.

[The prepared statement of Dr. Herzog follows:]

PREPARED STATEMENT OF ANTONIA HERZOG, STAFF SCIENTIST, CLIMATE CENTER, NATURAL RESOURCES DEFENSE COUNCIL

Thank you for the opportunity to testify today on the subject of coal gasification technology and the challenges it faces. My name is Antonia Herzog. I am a staff scientist in the Climate Center at the Natural Resources Defense Council (NRDC). NRDC is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington, Los Angeles and San Francisco.

One of the primary reasons that the electric power, chemical, and liquid fuels industries have become increasingly interested in coal gasification technology in the last several years is the volatility and high cost of both natural gas and oil. Coal has the advantages of being a cheap, abundant, and domestic resource compared with oil and natural gas. However, the disadvantages of conventional coal use cannot be ignored. From underground accidents and mountain top removal mining, to collisions at coal train crossings, to air emissions of acidic, toxic, and heat-trapping pollution from coal combustion, to water pollution from coal mining and combustion wastes, the conventional coal fuel cycle is among the most environmentally destructive activities on earth.[1]

But we can do better with both production and use of coal. And because the world is likely to continue to use significant amounts of coal for some time to come, we must do better. Energy efficiency remains the cheapest, cleanest, and fastest way to meet our energy and environmental challenges, while renewable energy is the fastest growing supply option. Increasing energy efficiency and expanding renewable energy supplies must continue to be the top priority, but we have the tools to make coal more compatible with protecting public health and the environment. With the right standards and incentives we can fundamentally transform the way coal is produced and used in the United States and around the world.

In particular, coal use and climate protection do not need to be irreconcilable activities. While energy efficiency and greater use of renewable resources must remain core components of a comprehensive strategy to address global warming, development and use of technologies such as coal gasification in combination with carbon dioxide (CO_2) capture and permanent disposal in geologic repositories under certain circumstances could enhance our ability to avoid a dangerous build-up of this heat-trapping gas in the atmosphere while creating a future for continued coal use.

However, because of the long lifetime of carbon dioxide in the atmosphere and the slow turnover of large energy systems we must act without delay to start deploying these technologies as appropriate. Current government policies are inadequate to drive the private sector to invest in carbon capture and disposal systems in the timeframe we need them. To accelerate the development of these systems and to create the market conditions for their use, we need to focus government funding more sharply on the most promising technologies. More importantly, we need to adopt binding measures and standards that limit global warming emissions so that the private sector has a business rationale for prioritizing investment in this area.

In addition, Congress should only allow new authorizations for expenditures or the commitment of federal fiscal resources, including an authorization for an appropriation, direct spending, tax measures, loan guarantees or other credit instruments, to support the research, development, demonstration or commercial deployment of an energy producing technology if that technology, when commercially deployed: (A) reduces greenhouse gas emissions, (B) reduces our dependence on oil; and (C) provides an economic benefit to the U.S. economy.

Congress is now considering a variety of proposals to gasify coal as a replacement for natural gas and oil. These proposals need to be evaluated in the context of the compelling need to reduce global warming emissions steadily and significantly, starting now and proceeding constantly throughout this century. Furthermore, because today's coal mining and use also continues to impose a heavy toll on America's land, water, and air, damaging human health and the environment, it is also critical to examine the implications of a substantial coal gasification program on these values as well.

[1] "Coal in a Changing Climate," NRDC position paper, February 2007, http://www.nrdc.org/globalWarming/coal/coalclimate.pdf.

REDUCING NATURAL GAS AND OIL DEMAND

The nation's economy, our health and our quality of life depend on a reliable supply of affordable energy services. The most significant way in which we can achieve these national goals is to exploit the enormous scope to wring more services out of each unit of energy used and by aggressively promoting renewable resources. While coal gasification technology has been touted as the technology solution to supplement our natural gas and oil supply and reduce our dependence on natural gas and oil imports, the most effective way to lower natural gas and oil demand, and prices, is to waste less. America needs to first invest in energy efficiency and conservation to reduce demand, and to second promote renewable energy alternatives to supplement supply. Gasified coal may have a role to play, but in both the short-term and over the next two decades, efficiency and renewables are the lead actors in an effective strategy to moderate natural gas and oil prices and balance our demand with reasonable expectations of supply.

Natural Gas

Increasing energy efficiency is far-and-away the most cost-effective way to reduce natural gas consumption and avoid emitting carbon dioxide and other damaging environmental impacts. Available technologies range from efficient lighting, including emerging L.E.D. lamps, to advanced selective membranes which reduce industrial process energy needs. Critical national and state policies include appliance efficiency standards, performance-based tax incentives, utility-administered deployment programs, and innovative market transformation strategies that make more efficient designs standard industry practice.

Conservation and efficiency measures such as these can have dramatic impacts in terms of price and savings.[2] Moreover, all of these untapped gas efficiency "resources" will expand steadily, as a growing economy adds more opportunities to secure long-lived savings. California has aquarter century record of using comparable strategies to reduce both natural gas consumption and the accompanying utility bills. Recent studies commissioned by the Pacific Gas & Electric Company showed that by 2001 longstanding incentives and standards targeting natural gas equipment and use had cut statewide consumption for residential, commercial, and industrial purposes (excluding electric generation) by more than 20 percent.

Studies have consistently shown that reducing demand for natural gas by increasing renewable energy use will reduce natural gas prices. According to a report released by the U.S. Department of Energy's Lawrence Berkeley National Laboratory, "studies generally show that each 1% reduction in national gas demand is likely to lead to a long-term (effectively permanent) average reduction in wellhead gas prices of 0.8% to 2%. Reductions in wellhead prices will reduce wholesale and retail electricity rates and will also reduce residential, commercial, and industrial gas bills."[3]

Adoption of a national renewable energy standard (RES) can significantly reduce the demand for natural gas, alleviating potential shortages. The Energy Information Administration (EIA) has found that a national 10 percent renewable energy standard could reduce gas consumption by 1.4 trillion cubic feet per year in 2020 compared to business as usual, or roughly 5 percent of annual demand. Furthermore, there would be a $4.9 billion cumulative present value savings for industrial gas consumers, $1.8 billion to commercial customers, and $2.4 billion to residential customers.[4] EIA also found that renewable energy can help reduce electricity bills. Lower natural gas prices for electricity generators and other consumers offset the slightly higher cost of renewable electricity technology.[5]

Implementing effective energy efficiency measures is the fastest and most cost effective approach to balancing natural gas demand and supply. Renewable energy provides a critical mid-term to long-term supplement. Analysis by the Union of Concerned Scientists found that a combined efficiency and renewable energy scenario

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[2] American Council for an Energy-Efficient Economy (ACEEE), Fall 2004 Update on Natural Gas Markets, November 3, 2004. See also Consumer Federation of America, "Responding to Turmoil in Natural Gas Markets: The Consumer Case for Aggressive Policies to Balance Supply and Demand," pp. 28, December 2004.

[3] U.S. Department of Energy, Lawrence Berkeley National Laboratory, Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Increased Deployment of Renewable Energy and Energy Efficiency, January, 2005, p. 13.

[4] EIA, Impacts of a 10-Percent Renewable Portfolio Standard, SR/OIAF/2002-03, February 2002. EIA, Analysis of a 10-Percent Renewable Portfolio Standard, SR/OIAF/2003-01, May 2003.

[5] UCS, Renewable Energy Can Help Alleviate Natural Gas Crisis, June 2003, at 2.

could reduce gas use by 31 percent and natural gas prices by 27 percent compared to business as usual in 2020.[6]

In contrast to these strategies, pursuing coal gasification implementation strategies that address only natural gas supply concerns, while ignoring impacts of coal, is a recipe for huge and costly mistakes. Fortunately, we have in our tool box energy resource options that can reduce natural gas demand and global warming emissions as well as protecting America's land, water, and air.

Oil

NRDC fully agrees that reducing oil dependence should be a national priority and that new policies and programs are needed to avert the mounting problems associated with today's dependence and the much greater dependence that lies ahead if we do not act. A critical issue is the path we pursue in reducing oil dependence: a "green" path that helps us address the urgent problem of global warming and our need to reduce the impacts of energy use on the environment and human health; or a "brown" path that would increase global warming emissions as well as other health and environmental damage. In deciding what role coal might play as a source of transportation fuel NRDC believes we must thoroughly assess whether it is possible to use coal to make liquid fuels without exacerbating the problems of global warming, conventional air pollution and impacts of coal production and transportation.

If coal were to play a significant role in displacing oil, it is clear that the enterprise would be huge, so the health and environmental stakes are correspondingly huge. The coal company Peabody Energy is promoting a vision that would call for production of 2.6 million barrels per day of synthetic transportation fuel from coal by 2025, about 10% of forecasted oil demand in that year. According to Peabody, using coal to achieve that amount of crude oil displacement would require construction of 33 very large coal-to-liquids plants, each plant consuming 14.4 million tons of coal per year to produce 80,000 barrels per day of liquid fuel. Each of these plants would cost $6.4 billion to build. Total additional coal production required for this program would be 475 million tons of coal annually—requiring an expansion of coal mining of 43% above today's leve1.[7] This testimony does not attempt a thorough analysis of the impacts of a program of this scale. Rather, it will highlight the issues that should be addressed in a detailed assessment.

ENVIRONMENTAL IMPACTS OF COAL

Some call coal "clean." It is not and likely never will be compared to other energy options. Nonetheless, it appears inevitable that the U.S. and other countries will continue to rely heavily on coal for many years. The good news is that with the right standards and incentives it is possible to chart a future for coal that is compatible with protecting public health, preserving special places, and avoiding dangerous global warming. It may not be possible to make coal clean, but by transforming the way coal is produced and used, it is possible to make coal significantly cleaner—and safer—than it is today.

Global Warming Pollution

To avoid catastrophic global warming the U.S. and other nations will need to deploy energy resources that result in much lower releases of CO_2 than today's use of oil, gas and coal. To keep global temperatures from rising to levels not seen since before the dawn of human civilization, the best expert opinion is that we need to get on a pathway now to allow us to cut global warming emissions by up to 80 percent from today's levels over the decades ahead. The technologies we choose to meet our future energy needs must have the potential to perform at these improved emission levels.

Most serious climate scientists now warn that there is a very short window of time for beginning serious emission reductions if we are to avoid truly dangerous greenhouse gas reductions without severe economic impact. Delay makes the job harder. The National Academy of Sciences recently stated: "Failure to implement significant reductions in net greenhouse gases will make the job much harder in the

[6] UCS, Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future, October 2001.

[7] Peabody's "Eight-Point Plan" calls for a total of 1.3 billion tons of additional coal production by 2025, proposing that coal be used to produce synthetic pipeline gas, additional coal-fired electricity, hydrogen, and fuel for ethanol plants. The entire program would more than double U.S. coal mining and consumption.

future—both in terms of stabilizing their atmospheric abundances and in terms of experiencing more significant impacts."[8]

In short, a slow start means a crash finish—the longer emissions growth continues, the steeper and more disruptive the cuts required later. To prevent dangerous global warming we need to stabilize atmospheric concentration at or below 450 ppm, which would keep total warming below 2 degrees Celsius (3.6 degrees Fahrenheit). If we start soon, we can stay on the 450 ppm path with an annual emission reduction rate that gradually ramps up, but if we delay a serious start by 10 years or more and continue emission growth at or close to the business-as-usual trajectory, the annual emission reduction rate required to stay on the 450 ppm pathway jumps many-fold[9]. Even if you do not accept today that the 450 ppm path will be needed consider this point. If we do not act to preserve our ability to get on this path we will foreclose the path not just for ourselves but for our children and their children. We are now going down a much riskier path and if we do not start reducing emissions soon neither we nor our children can turn back no matter how dangerous the path becomes.

In the past, some analysts have argued that the delay/crash action scenario is actually the cheaper course, because in the future (somehow) we will have developed breakthrough technologies. But it should be apparent that the crash reductions scenario is implausible for two reasons. First, reducing emissions by a very high rate each year would require deploying advanced low-emission technologies at least several times faster than conventional technologies have been deployed over recent decades. Second, the effort would require prematurely retiring billions of dollars in capital stock—high-emitting power plants, vehicles, etc.—that will be built or bought during the next 10-20 years under in the absence of appropriate CO_2 emission limits. It also goes without saying that U.S. leadership is critical. Preserving the 450 ppm pathway requires other developed countries to reduce emissions at similar rates, and requires the key developing countries to dramatically reduce and ultimately reverse their emissions growth. U.S. leadership can make that happen faster.

To assess the global warming implications of a large coal gasification program we need to carefully examine the total life-cycle emissions associated with the end product, whether electricity, synthetic gas, liquid fuels or chemicals, and to assess if the relevant industry sector will meet the emission reductions required to be consistent with what we need to achieve in the U.S.

Electricity Sector

More than 90 percent of the U.S. coal supply is used to generate electricity in some 600 coal-fired power plants scattered around the country, with most of the remainder is used for process heat in heavy industrial and in steel production. Coal is used for power production in all regionsof the country, with the Southeast, Midwest, and Mountain states most reliant on coal-fired power. Texas uses more coal than any other state, followed by Indiana, Illinois, Ohio, and Pennsylvania.[10]

About half of the U.S. electricity supply is generated using coal-fired power plants. This share varies considerably from state to state, but even California, which uses very little coal to generate electricity within its borders, consumes a significant amount of electricity generated by coal in neighboring Arizona and Nevada, bringing coal's share of total electricity consumed in California to 20 percent.[11] National coal-fired capacity totals 330 billion watts (GW), with individual plants ranging in size from a few million watts (MW) to over 3000 MW. More than one-third of this capacity was built before 1970, and over 400 units built in the 1950s—with capacity equivalent to roughly 100 large modern plants (48 GW)—are still operating today.

The future of coal in the U.S. electric power sector is an uncertain one. The major cause of this uncertainty is the government's failure to define future requirements for limiting greenhouse gas emissions, especially carbon dioxide (CO_2). Coal is the fossil fuel with the highest uncontrolled CO_2 emission rate of any fuel and is responsible for 36 percent of U.S. carbon dioxide emissions. Furthermore, coal power plants are expensive, long-lived investments. Key decision makers understand that the problem of global warming will need to be addressed within the time needed

[8] National Academy of Sciences, Understanding and Responding to Climate Change: Highlights of National Academies Reports, p.16 (October 2005), http://dels.nas.edu/dels/rpt briefs/climate-change-final.pdf.

[9] D. D. Doniger, A.V. Herzog, D. A. Lashof, "An Ambitious, Centrist Approach to Global warming Legislation," Science, vol. 314, p. 764 (November, 2006).

[10] http://www.eia.doe.gov/cneaf/coal/page/acr/table26.html.

[11] California Energy Commission, 2005. 2004 Net System Power Calculation (April.) Table 3: Gross System Power. http://www.energy.ca.gov/2005publications/CEC-300-2005-004/CEC-300-2005-004.PDF.

to recoup investments in power projects now in the planning stage. Since the status quo is unstable and future requirements for coal plants and other emission sources are inevitable but unclear, there will be increasing hesitation to commit the large amounts of capital required for new coal projects.

Electricity production is the largest source of global warming pollution in the U.S. today. In contrast to nitrogen and sulfur oxide emissions, which have declined significantly in recent years as a result of Clean Air Act standards, CO_2 emissions from power plants have increased by 27 percent since 1990. Any solution to global warming must include large reductions from the electric sector. Energy efficiency and renewable energy are well-known low-carbon methods that are essential to any climate protection strategy. But technology exists to create a more sustainable path for continued coal use in the electricity sector as well. Coal gasification can be compatible with significantly reducing global warming emissions in the electric sector if it replaces conventional coal combustion technologies, directly produces electricity in an integrated manner, and most importantly captures and disposes of the carbon in geologic formations. IGCC technology without CO_2 capture and disposal achieves only modest reductions in CO_2 emissions compared to conventional coal plants.

A coal integrated gasification combined cycle (IGCC) power plant with carbon capture and disposal can capture up to 90 percent of its emissions, thereby being part of the global warming solution. In addition to enabling lower-cost CO_2 capture, gasification technology has very low emissions of most conventional pollutants and can achieve high levels of mercury control with low-cost carbon-bed systems. However, it still does not address the other environmental impacts from coal production and transportation.

The electric power industry has been slow to take up gasification technology, but two commercial-scale units are operating in the U.S.—in Indiana and Florida. The Florida unit, owned by TECO, is reported by the company to be the most reliable and economic unit on its system. Two coal-based power companies, AEP and Cinergy, have announced their intention to build coal gasification units. The first proposed coal gasification plant that will capture and dispose of its CO_2 was announced in February, 2006 by BP and Edison Mission Group. The plant will be built in Southern California and its CO_2 emissions will be pipelined to an oil field nearby and injected into the ground to recover domestic oil. BP's proposal shows the technologies are available now to cut global warming pollution and that integrated IGCC with CO_2 capture and disposal are commercially feasible.

Liquid Fuels

To assess the global warming implications of a large coal-to-liquids program we need to examine the total life-cycle or "well-to-wheel" emissions of these new fuels. Coal is a carbon-intensive fuel, containing double the amount of carbon per unit of energy compared to natural gas and about 20% more than petroleum. When coal is converted to liquid fuels, two streams of CO_2 are produced: one at the coal-to-liquids production plant and the second from the exhausts of the vehicles that burn the fuel. With the technology in hand today and on the horizon it is difficult to see how a large coal-to-liquids program can be compatible with the low-CO_2-emitting transportation system we need to design to prevent global warming.

Today, our system of refining crude oil to produce gasoline, diesel, jet fuel and other transportation fuels, results in a total "well-to-wheels" emission rate of about 27.5 pounds of CO_2 per gallon of fuel. Based on available information about coal-to-liquids plants being proposed, the total well to wheels CO_2 emissions from such plants would be about 49.5 pounds of CO_2 per gallon, nearly twice as high as using crude oil, if the CO_2 from the coal-to-liquids plant is released to the atmosphere.[12] Obviously, introducing a new fuel system with close to double the CO_2 emissions of today's crude oil system would conflict with the need to reduce global warming emissions. If the CO_2 from coal-to-liquids plants is captured, then well-to-wheels CO_2 emissions would be reduced but would still be higher than emissions from today's crude oil system.[13]

This comparison indicates that using coal to produce a significant amount of liquids for transportation fuel would not be compatible with the need to develop a low-

[12] Calculated well-to-wheel CO_2 emissions for coal-based "Fischer-Tropsch" are about 1.8 greater than producing and consuming gasoline or diesel fuel from crude oil. If the coal-to-liquids plant makes electricity as well, the relative emissions from the liquid fuels depends on the amount of electricity produced and what is assumed about the emissions of from an alternative source of electricity.

[13] Capturing 90 percent of the emissions from coal-to-liquid plants reduces the emissions from the plant to levels close to those from petroleum production and refining while emissions from the vehicle are equivalent to those from a gasoline vehicle. With such CO_2 capture, well to wheels emissions from coal-to-liquids fuels would be 8 percent higher than for petroleum.

CO_2 emitting transportation sector unless technologies are developed to significantly reduce emissions from the overall process. But here one confronts the unavoidable fact that the liquid fuel from coal contains the same amount of carbon as is in gasoline or diesel made from crude. Thus, the potential for achieving significant CO_2 emission reductions compared to crude is inherently limited. This means that using a significant amount of coal to make liquid fuel for transportation needs would make the task of achieving any given level of global warming emission reduction much more difficult. Proceeding with coal-to-liquids plants now could leave those investments stranded or impose unnecessarily high abatement costs on the economy if the plants continue to operate.

NRDC has examined the greenhouse gas emissions from a wide variety of feedstock and conversion process combinations using the Argonne GREET model (see figure 1* and Appendix 1). EPA conducted a similar analysis for a factsheet released in conjunction with its final rule for implementing the Renewable Fuels Standard enacted in EPACT 2005.[14] EPA's results are shown in Figure 2 and are very similar to ours (note that EPA displays results relative to conventional diesel gasoline, which is set to zero on their chart). Most recently Argonne National Laboratory scientist released a new analysis using their GREET model to assess the life-cycle greenhouse gas emissions of Fischer-Tropsch diesel products from natural gas, coal and biomass (see figure 3).[15] Again their results are similar to ours. They find that liquid coal without carbon capture and disposal can emit from 2.2 to 2.5 times more greenhouse gases than the equivalent gallon of petroleum-based diesel fuel. And even with carbon capture and disposal the life-cycle emissions are still 1.19-1.25 times higher.

From these charts we can clearly see that there are much more environmentally friendly methods for producing transportation fuels. Biofuels are an obvious alternative, which has gotten a lot of attention recently, and about which NRDC recently testified before the committee.[16] Another alternative transportation fuel that is worthy of note is electricity used in plug-in hybrid electric vehicles. If coal is to be used to replace gasoline, generating electricity for use in plug-in hybrid vehicles (PHEVs) can be far more efficient and cleaner than making liquid fuels. In fact, a ton of coal used to generate electricity used in a PHEV will displace more than twice as much oil as using the same coal to make liquid fuels, even using optimistic assumptions about the conversion efficiency of liquid coal plants.[17] The difference in CO_2 emissions is even more dramatic. Liquid coal produced with CCS and used in a hybrid vehicle would still result in lifecycle greenhouse gas emissions of approximately 330 grams/mile, or ten times as much as the 33 grams/mile that could be achieve by a PHEV operating on electricity generated in a coal-fired power plant equipped with CCS.[18] GM has recently announced plans to commercialize plug-in hybrid electric vehicles.

Simply put, liquid coal is highly unlikely to be compatible with long-term climate protection. A recent analysis by Jim Dooley of Battelle National Laboratory shows that liquid coal is not part of an energy system that is consistent with stabilizing greenhouse gas concentrations at or below 450ppm. (see figure 4).[19] Furthermore, using high-carbon fuels for transportation means we would have to do that much more in improving other areas of transportation, such as increased vehicle efficiency and reduced vehicle miles traveled. The Administration's alternative fuels proposal highlights this fact. If half of the alternative fuels mandate proposed by the administration were satisfied with coal-derived liquid fuels then CO_2 emissions would be 175 million tons higher in 2017 than the administration's target. To offset this increase through automobile fuel efficiency standards would have to increase by 8.6

* Figures 1-5 have been retained in committee files.

[14] http://www.epa.gov/otaq/renewablefuels/420f07035.htm

[15] M. Wang, M. Wu, H. Huo, "Life-cycle energy and greenhouse gas results of Fischer-Tropsch diesel produced from natural gas, coal, and biomass," Center for Transportation Research, Argonne National laboratory, presented at 2007 SAE Government/Industry meeting, Washington, DC, May 2007.

[16] Daniel Lashof, Testimony on S.987, the Biofuels for Energy Security and Transportation Act of 2007 before the Senate Energy and Natural Resources Committee, April 12, 2007. http://docs.nrdc.org/globalwarming/glo_07041201A.pdf.

[17] Assumes production of 84 gallons of liquid fuel per ton of coal, based on the National Coal Council report. Vehicle efficiency is assumed to be 37.1 miles/gallon on liquid fuel and 3.14 miles/kWh on electricity.

[18] Assumes lifecycle greenhouse gas emission from liquid coal of 27.3 lbs/gallon and lifecycle greenhouse gas emissions from an IGCC power plant with CCS of 106 grams/kWh, based on R. Williams et al., paper presented to GHGT-8 Conference, June 2006.

[19] Jim Dooley, Robert Dahowski, Marshall Wise, Casie Davidson "Coal-to-Liquids and Advanced Low-Emissions Coal-fired Electricity Generation," presentation at NETL conference, May 9, 2007, PNWD-SA-7804.

percent per year, rather than the 4 percent per year as suggested by the administration.

With liquid coal proposals proliferating in Congress it is critical to evaluate the environmental ramifications of these proposals. In particular, recently offered before the Senate Energy and Natural Resources committee during their May 2, 2007 energy legislation markup was an amendment co-authored by Senators Thomas and Bunning mandating 21 billion gallons of liquid coal synfuels per year by 2022.

Producing 21 billion gallons of liquid coal synfuels per year would require building up to 40 new medium sized (35,000 barrels/day) liquid coal plants. This in turn would:

- Increase global warming pollution by almost 600 million metric tons CO_2 per year. Even with carbon capture and disposal CO_2 emissions are still higher than conventional fuels, and while cofiring with biomass with carbon capture and disposal can produce diesel fuels with life-cycle emissions below conventional diesel fuels, this technology is still in the development stages.
- Create water shortages in the West by requiring an additional 100 billion gallons of water usage per year, the equivalent of 375 empire state buildings of water per year. One gallon of liquid coal requires five gallons of water to produce. It is expected that many of the forty new coal plants required to produce this fuel would be built in the West where water shortages are already a severe problem.
- Scar the landscape by requiring 250 million additional tons of coal, a 23% increase in coal mining compared to 2006 coal mining production. This increase would have severe impacts on our land, air and water.

While Senators Thomas and Bunning have acknowledged the importance of global warming pollution by requiring that emissions from liquid coal synfuels not exceed those from conventional gasoline we need to be doing much better than that to meet the emission reductions that will be necessary from the transportation sector (see figure 4).

Synthetic Gas

Another area that has received interest is coal gasification to produce synthetic natural gas as a direct method of supplementing our natural gas supply from domestic resources. However, without CO_2 capture and disposal this process results in more than twice as much CO_2 per 1000 cubic feet of natural gas consumed compared to conventional resources.[20] From a global warming perspective this is unacceptable. With capture and disposal the CO_2 emissions can be substantially reduced, but still remain 12 percent higher than natural gas.

In Beulah, North Dakota the Basin Electric owned Dakota Gasification Company's Great Plains Synfuels Plant is a 900MW facility which gasifies coal to produce synthetic "natural" gas. It can produce 150 million cubic feet of synthetic gas per day and 11,000 tons of CO_2 per day. However, it no longer releases all of its CO_2 to the atmosphere, but captures most of it and pipes it 200 miles to an oil field near Weyburn, Saskatchewan. There the CO_2 is pumped underground into an aging oil field to recover more oil. EnCana, operator of this oil field, pays $2.5 million per month for the CO_2. They expect to sequester 20 million tons of CO_2 over the lifetime of this injection project.

A potential use for coal-produced synthetic gas would be to burn it in a gas turbine at another site for electricity generation. This approach would result in substantially higher CO_2 emissions than producing electricity in an integrated system at the coal gasification plant with CO_2 capture at the site (i.e., in an IGCC plant with carbon capture and disposal). Coal produced synthetic natural gas could also be used directly for home heating. As a distributed source of emissions the CO_2 would be prohibitive to capture with known technology.

Before producing synthetic pipeline gas from coal a careful assessment of the full fuel cycle emissions against the baseline and alternatives and the emission reductions that are required from that sector must be carried out before decisions are made to invest in these systems.

Chemical Products

The chemical industry has also been looking carefully at coal gasification technology as a way to replace the natural gas feedstock used in chemical production.

[20] The National Coal Council, "Coal: America's Energy Future," March 22, 2006. This report actually assumes a less efficient coal to synthetic gas conversion process of 50% leading to three times as much CO_2 per 1000 cubic feet of natural gas consumed compared to conventional resources.

The motivator has been the escalating and volatile costs of natural gas in the last few years. A notable example in the U.S. of such a use is the Tennessee Eastman plant, which has been operating for more than 20 years using coal instead of natural gas to make chemicals and industrial feedstocks. If natural gas is replaced by coal gasification as a feedstock for the chemical industry, first and foremost CO_2 capture and disposal must be an integral part of such plants. In this case, the net global warming emissions will change relatively little from this sector compared to the conventional natural gas based process. Steam reforming of natural gas, however, could also potentially capture its emissions too, resulting in even lower emissions. Therefore, before such a transformation occurs with coal as a feedstock, a careful analysis of the entire life cycle emissions needs to be carried out against the baseline and alternatives, along with an assessment of how future emissions reductions from this sector can be most effectively accomplished.

Conventional Air Pollution

Dramatic reductions in power plant emissions of criteria pollutants, toxic compounds, and global warming emissions are essential if coal is to remain a viable energy resource for the 21st Century. Such reductions are achievable in integrated gasification combined cycle (IGCC) systems, which enable cost-effective advanced pollution controls that can yield extremely low criteria pollutant and mercury emission rates and facilitates carbon dioxide capture and geologic disposal. Gasifying coal at high pressure facilitates removal of pollutants that would otherwise be released into the air such that these pollutant emissions are well below those from conventional pulverized coal power plants with post combustion cleanup.

Conventional air emissions from coal-to-liquids plants include sulfur oxides, nitrogen oxides, particulate matter, mercury and other hazardous metals and organics. While it appears that technologies exist to achieve high levels of control for all or most of these pollutants, the operating experience of coal-to-liquids plants in South Africa demonstrates that coal-to-liquids plants are not inherently "clean." If such plants are to operate with minimum emissions of conventional pollutants, performance standards will need to be written—standards that do not exist today in the U.S. as far as we are aware.

In addition, the various federal emission cap programs now in force would apply to few, if any, coal-to-liquids plants.[21]

Thus, we cannot say today that coal-to-liquids plants will be required to meet stringent emission performance standards adequate to prevent either significant localized impacts or regional emissions impacts.

Mining, Processing and Transporting Coal

The impacts of mining, processing, and transporting 1.1 billion tons of coal today on health, landscapes, and water are large. To understand the implications of continuing our current level of as well as expanding coal production, it is important to have a detailed understanding of the impacts from today's level of coal production. It is clear that we must find more effective ways to reduce the impacts of mining, processing and transporting coal before we follow a path that would result in even larger amounts of coal production and transportation.

THE PATH FORWARD: AN ACTION PLAN TO REDUCE U.S. GLOBAL WARMING POLLUTION

The United Nations Framework Convention on Climate Change (UNFCCC) establishes the objective of preventing "dangerous anthropogenic interference with the climate system." While a "non-dangerous" concentration level has not been defined under the UNFCCC and is not a purely scientific concept, the European Union has set a goal of avoiding an increase of more than 2 degrees Celsius from pre-industrial levels in order to avoid the most dangerous changes to climate. We believe this is a sound goal and U.S. emission reduction policies should have a similar objective.

To prevent dangerous global warming while allowing for a reasonable transition in developing nations, the U.S. needs to start to cut global warming pollution as soon as possible and keep steadily reducing emissions over time. Specifically, U.S. emissions in 2020 should be at least 15-20% below current levels.[22] By mid-century,

[21] The sulfur and nitrogen caps in EPA's "Clean Air Interstate Rule" ("CAIR") may cover emissions from coal-toliquids plants built in the eastern states covered by the rule but would not apply to plants built in the western states. Neither the national "acid rain" caps nor EPA's mercury rule would apply to coal-to-liquids plants.

[22] 15% below 2005 levels is equivalent to 1990 levels, and is also equivalent to approximately 35% below businessas-usual levels for 2020. The Sander-Boxer Global Warming Pollution Reduction Act, S. 309, meets these emission reduction goals.

U.S. emissions need to be reduced on the order of 80 percent. A variety of existing technologies can be deployed to achieve these goals—and, in addition, the right policies will spur investment and innovation to create new fuels and technologies. By solving this smartly, we can create jobs and improve our standard of living even as we tackle this dangerous problem.

A valuable framework in which to visualize a long-term emissions reductions pathway is through the "wedges" analysis pioneered by Professors Robert Socolow and Steve Pacala at Princeton University.[23] NRDC has modified their study, which analyzed global emission reduction pathways, to consider potential U.S. emission reduction pathways.

The structure of our analysis is a detailed extension of the Socolow-Pacala concept of emission reduction "stabilization wedges" decreases in emissions in measurable increments from a business as usual projection attributable to specific technologies. These wedge increments can then be summed up in various ways (as "paths") to the desired emission reduction total (See figure 5).

NRDC used a spreadsheet model developed by Kuuskraa et al. to examine U.S. emissions scenarios out to 2050.[24] This analysis segregates the wedges into four sectors: electricity, transportation, stationary end-use fuel combustion, and non-CO_2 gases. This segregation helps to avoid double counting different measure so as to develop self-consistent scenarios for the U.S. energy system (for example, taking credit for reducing the demand of electricity from appliances while at the same time reducing emissions at power plants that supply the power).

Their spreadsheet model is used here to construct an emissions scenario consistent with the U.S. carbon budget that meets an 80 percent reduction below 1990 levels by 2050 using technologies that are likely to be available and affordable during that timeframe. In this scenario the largest reductions are obtained from energy efficiency improvements in electrical end uses, non-electric stationary end uses, and motor vehicles. Additional reductions come from renewable fuels and electricity and carbon capture and disposal at coal-fired power plants and other high-concentration industrial CO_2 vents. The elements of this scenario are briefly outlined below.

Electricity (first 3 wedges)—The U.S. gets just over half of its electricity from coal, about a fifth from nuclear power, and the balance mainly from natural gas and renewable energy sources. Natural gas is considered limited by supply and price constraints and hydroelectric power, the dominant renewable resource, is limited by the fact that the best available sites have already been dammed. In addition, the expansion of nuclear power continues to hit a variety of impediments. Therefore, for the electricity sector we assume:

- High levels of efficiency in end-use consumption and supply production and distribution to meet growing energy needs, thereby reducing the need to construct new baseload power plants while expanding renewable energy sources.
  - —40% of electricity (1600 Billion kWh) is generated from non-hydro renewables: Wind, geothermal, solar thermal, PV, and biomass (coproduced with biofuels).
- Building some coal plants with geologic carbon dioxide disposal to replace existing coal-fired plants as they reach retirement age.
  - —16% of electricity (660 Billion kWh) is generated from coal with carbon capture and geologic disposal.
- Nuclear would remain roughly the same proportion of electricity that it does currently.

Transportation (second 3 wedges)—Controlling emission from the burning of oil by the transportation sector requires a combination of reducing the number of miles people drive in their cars and other vehicles (Vehicle Miles Traveled or VMT), the efficiency of those vehicles in consuming as little fuel as possible, and the using low-carbon fuels. The low-carbon fuels wedge assumes that there will be adequate environmental protections for the production of these fuels, while at the same time promoting maximum efficiency and electrification of the vehicle fleet.

The scenario analyzed assumes:

- New vehicle fuel efficiency triples by 2050 and VMT is reduced by 20% through smart growth policies.

[23] S. Pacala and R. Socolow, "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies," Science, v. 305, p. 968 (2004).

[24] V. Kuuskraa, P. Dipietro, S. Klara, S. Forbes, "Future U.S. Greenhouse Gas Emission Reduction Scenarios Consistent with Atmospheric Stabilization Concentrations," GHGT-7, .506 (2004).

—New vehicle fuel efficiency is 3 times current level by 2050. On road fleet average 55 mpg.

- Of the remaining fuel demand, 45% is satisfied with electricity used in plug-in hybrid vehicles and 40% is satisfied by biofuels, such that biofuels displace 36 billion gallons of gasoline equivalent in 2050.[25]

Biological Sequestration and Other—There is a wedge that allows for a small amount of carbon dioxide to be absorbed by biological sources. While we do not support an over reliance on biological sequestration, because of a lack of reliability of such a mechanism, some biological sequestration is likely to occur. The other efficiency wedge incorporates efficiency improvements made in direct fuel demand by stationary sources and the other renewables wedge comes from renewables supplying 30 percent of other stationary source energy demand. Finally, there are other unidentified reduction opportunities, including international emissions trading.

This analysis clearly shows how we can meet the required emission reduction targets through the deployment of a wide variety of low-carbon technologies in multiple sectors of the economy over the next four decades. It is also clear that liquid coal is not compatible with this visions and would require the expansion of other low-carbon wedges to cover its emissions profile. Coal gasification for electricity production is consistent and integrated into the analysis. Further analysis is needed to assess whether the use of coal gasification for other products such as synthetic natural gas or chemicals would be at odds with the necessary reduction pathway.

CONCLUSION

The impacts that a large coal gasification program could have on global warming pollution, conventional air pollution and environmental damage resulting from the mining, processing and transportation of the coal are substantial. Before deciding whether to invest scores, perhaps hundreds of billions of dollars in deploying this technology, we must have a program to manage our global warming pollution and other coal related impacts. Otherwise we will not be developing and deploying an optimal energy system.

One of the primary motivators for pushing coal gasification technologies has been to reduce natural gas prices. Fortunately, the U.S. can have a robust and effective program to reduce natural gas demand, and therefore prices, without rushing to embrace coal gasification technologies. A combination of efficiency and renewables can reduce our natural gas demand more quickly and more cleanly.

The other major motivator for the push to use coal gasification is to produce liquid fuels to reduce our oil dependence. The U.S. can have a robust and effective program to reduce oil dependence without rushing into an embrace of liquid coal technologies. A combination of more efficient cars, trucks and planes, biofuels, and “smart growth” transportation options outlined above and in the report “Securing America,” produced by NRDC and the Institute for the Analysis of Global Security, which shows how to cut oil dependence by more than 3 million barrels a day in 10 years, and achieve cuts of more than 11 million barrels a day by 2025.

To reduce our dependence on natural gas and oil we should follow a simple rule: start with the measures that will produce the quickest, cleanest and least expensive reductions in natural gas and oil use; measures that will put us on track to achieve the reductions in global warming emissions we need to protect the climate. If we are thoughtful about the actions we take, our country can pursue an energy path that enhances our security, our economy, and our environment.

With current coal and oil consumption trends, we are headed for a doubling of CO_2 concentrations by mid-century if we don’t redirect energy investments away from carbon based fuels and toward new climate friendly energy technologies. We have to accelerate the progress underway and adopt policies in the next few years to turn the corner on our global warming emissions, if we are to avoid locking ourselves and future generations into a dangerously disrupted climate. Scientists are very concerned that we are very near this threshold now. Most say we must keep atmosphere concentrations of CO_2 below 450 parts per million, which would keep total warming below 2 degrees Celsius (3.6 degrees Fahrenheit). Beyond this point we risk severe impacts, including the irreversible collapse of the Greenland Ice Sheet and dramatic sea level rise. With CO_2 concentrations now rising at a rate of 1.5 to 2 parts per million per year, we will pass the 450ppm threshold within two or three decades unless we change course soon.

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[25] Assuming that about half of corn stover can be collected for energy use (200 million tons of waste material altogether), 22 million acres would have to be dedicated to energy crop production.

In the United States, a national program to limit carbon dioxide emissions must be enacted soon to create the market incentives necessary to shift investment into the least-polluting energy technologies on the scale and timetable that is needed. There is growing agreement between business and policy experts that quantifiable and enforceable limits on global warming emissions are needed and inevitable.[26] To ensure the most cost-effective reductions are made, these limits can then be allocated to major pollution sources and traded between companies, as is currently the practice with sulfur emissions that cause acid rain. Further complimentary and targeted energy efficiency and renewable energy policies are critical to achieving CO_2 limits at the lowest possible cost, but they are no substitute for explicit caps on emissions.

A coal integrated gasification combined cycle (IGCC) power plant with carbon capture and disposal can also be part of a sustainable path that reduces both natural gas demand and global warming emissions in the electricity sector. Methods to capture CO_2 from coal gasification plants are commercially demonstrated, as is the injection of CO_2 into geologic formations for disposal.[27] On the other hand, coal gasification to produce a significant amount of liquids for transportation fuel would not be compatible with the need to develop a low-CO_2 emitting transportation sector. Finally, gasifying coal to produce synthetic pipeline gas or chemical products needs a careful assessment of the full life cycle emission implications and the emission reductions that are required from those sectors before decisions are made to invest in these practices.

The CHAIRMAN. All right. Thank you very much. That's very useful.

Mr. Fulkerson, go right ahead.

STATEMENT OF WILLIAM FULKERSON, SENIOR FELLOW, INSTITUTE FOR A SECURE AND SUSTAINABLE ENVIRONMENT, UNIVERSITY OF TENNESSEE, KNOXVILLE, TN

Mr. FULKERSON. Mr. Chairman and members of the committee, I am very pleased to have been invited to testify at this hearing on coal gasification, synfuels, and related topics.

What I'm going to say today derives mostly from what I consider to be the brilliant work of Bob Williams and his colleagues at Princeton University. I'm pinch-hitting for Bob today, since he is lecturing in China right now.

The story Bob would have told you, however, I think is extremely important for the committee's deliberations. So, maybe my pinch-hitting, no matter how bad it is, is warranted.

Let me give you a little background. Since retiring from the Oak Ridge National Laboratory in 1994, I have had the privilege of chairing a committee of people from 14 DOE National Labs, which we call the Laboratory Energy R&D Working Group, or LERDWG. We meet several times a year in Washington to talk about energy R&D policy, and about what's new and exciting in energy science and technology. At the April meeting of our group, Bob Williams talked about his idea for coal biomass gasification in a complex producing gasoline and diesel fuels via the Fischer-Tropsch synthesis process, as well as coal production of electricity and the sequestration of excess CO_2 produced. This idea addresses the coupled problems that everybody has said already of oil security, or oil dependence, and climate change mitigation. I call this scheme biocoal fuels.

[26] U.S. Climate Action Partnership, http://www.us-cap.org.

[27] David Hawkins, Testimony on S. 731 and S. 962: Carbon Capture and Sequestration before the Senate Energy and Natural Resources Committee, April 16, 2007. http://docs.nrdc.org/globalwarming/glo__07041601A.pdf.

By carefully matching the feedstocks of biomass and coal in this process, and capturing and storing the excess CO_2, sufficient CO_2 can be captured to offset the carbon in the product fuels that you produce—conventional, diesel, and gasoline—and that's a big idea. That's a big idea.

Why does that work? Well, it works, because most of the carbon in the biomass is sequestered. That's a net negative which offsets the emission of carbon from burning gasoline and diesel that you produce.

Bob shows that if CO_2, sequestered, has a value greater than, let's say, about $25 per ton, which is roughly the magnitude of the MIT report, where sequestration begins to become economically justified, then the process can produce competitive fuels at a competitive price, compared to petroleum, if oil prices are greater than $50 a barrel, which they're presently at, of course.

Another really important part of this scheme is that the ratio of the biomass that you need—biomass energy input that you need to produce a unit of energy fuel output is about one or less, and that means that this process would be two or three times—could produce two or three times as much carbon-free fuel as, for example, cellulosic, enzymatic ethanol would produce. Now, this remarkable result derives from the fact that much of the energy to run the process, the overall process, comes from coal. This means that biomass resource productivity can be greatly expanded. In fact, Williams makes a very interesting thought experiment. He asks, "What fraction of the transportation fuels from North America might his carbon-neutral biocoal route provide?" The answer is that all the fuels estimated to be required by 2050, for transportation of all sorts for North America, could be produced from the estimated 1.3 billion tons per year of biomass potentially available on a sustainable basis for energy, as estimated by the Department of Energy and the United States—and the USDA. This resource includes agricultural and forest residues, municipal waste, as well as biomass energy crops, the latter providing maybe 30 percent of the total resource to avoid excessive land use.

But this can only be accomplished—as Dr. Herzog indicated—it can only be accomplished, however, if light-duty vehicle fleet has an average fuel efficiency of about 60 miles per gallon. I drove up in my Prius car, and I only got, well, close to 50 miles per gallon. So, can we get 60, on average, by 2050? That's the question. So, that's one requirement.

Also, such a huge syn-fuels thing, which, of course, is much bigger would double the current use of coal. But we're pretty rich in coal, if we can just solve the other environmental problems associated with increased use.

Well, this is a rough summary of Bob Williams' great idea. I understand that he will submit written testimony to the committee to supply the details.

The scheme depends, of course, on sequestered CO_2 having a value—and that's up to you guys—and sequestration working at a large scale.

Finally, in my written testimony, I list six policies suggested by Williams that I believe could encourage innovation in developing solutions to our coupled problems of oil dependence and climate change mitigation. The policies are designed to be largely technology-neutral to avoid picking winners. Of course, it's easy to make such a list. The hard work comes from sorting out the many options so that policies are effective, and that they're fair, and that they're politically possible. And I think that's your job, and it's a difficult one, and I don't envy you at all. But it is so important that you take on the challenge. And I'm glad to see you're doing it.

[The prepared statement of Mr. Fulkerson follows:]

PREPARED STATEMENT OF WILLIAM FULKERSON, SENIOR FELLOW, INSTITUTE FOR A SECURE AND SUSTAINABLE ENVIRONMENT, UNIVERSITY OF TENNESSEE, KNOXVILLE, TN

Mr. Chairman and Members of the Committee, I am pleased to have been asked to testify at this hearing on coal gasification, synfuels and related topics. What I will say today derives mostly from the brilliant work of Bob Williams and his colleagues at Princeton University. I am pinch-hitting for Bob since he is lecturing in China today. What Bob and his colleagues have concluded from their analysis is very important to the issues being considered by this Committee. I believe he is right else I wouldn't be here.

Since retiring from the Oak Ridge National Laboratory in 1994 I have had the pleasure of chairing a committee of people from 14 DOE national laboratories. It is called the Laboratory Energy R&D Working Group or LERDWG. We meet several times a year in Washington to talk about energy R&D policy and about what is new and exciting in energy science and technology. In fact staff from this Committee often come to our meetings.

At our April meeting Bob Williams talked to us about his idea for a coal/biomass gasification complex producing gasoline and Diesel fuel via Fisher-Tropsch synthesis as well as co-production of electricity. Bob is interested in addressing the coupled challenges of oil security and climate change mitigation. Of course, liquid fuels from coal can be produced using oxygen blown gasification and Fisher-Tropsch, but this will result in about twice the amount of CO_2 vented compared to producing the same quantity of fuels from petroleum. If petroleum costs $50/bbl or more this synfuels process can be competitive. If the excess CO_2 produced is sequestered instead of vented then the coal synfuels process can be equivalent to petroleum in net CO_2 emissions.

But Williams points out we can do much better than petroleum if we gasify biomass with the coal in the same facility, and if the excess CO_2 produced is captured and stored in deep saline aquifers or is used for enhanced oil recovery from depleted oil reservoirs. In fact, the CO_2 captured and stored can be sufficient to offset the carbon in the fuel product so that the overall system including the carbon released by burning of the fuel produced can be a net zero in emissions. This is because most of the carbon in the biomass is captured as CO_2 and is sequestered offsetting the carbon released in product fuel burning. Of course the carbon in the biomass is extracted from the air during its growing. Burning the fuel produced merely returns carbon to the atmosphere from whence it came, and the cycle is completed with no net additions to the atmosphere. So, Bob shows that if CO_2 sequestered has a value of greater than $25/t the process can be competitive with fuels derived from petroleum if petroleum costs more than $50/bbl.

Another important feature of this scheme is that the ratio of biomass energy input to product fuel energy output is of the order of unity. This means that 2-3 times as much fuel can be produced per unit of biomass energy as from the cellulosic ethanol enzymatic process, for example. This remarkable result derives from the fact that much of the energy to run the process comes from coal. This means that the biomass resource productivity can be greatly expanded.

The productivity can be pushed even further by using mixed prairie grasses grown on carbon deficient soils as suggested in the recent paper in Science Magazine (Tilman, D., et al, Science, 314, 1598-1600, 8 Dec. 2006). These researchers from the University of Minnesota found that mixed prairie grasses sequestered up to 0.6 kg of carbon in roots and soil per kg of prairie grass harvested and this can happen year after year since the grasses are perennials. Using mixed prairie grass as the biomass feedstock in the process requires only about 0.6 GJ of biomass per GJ of product fuel is required. This biomass productivity is most important because the biomass resource is limited.

Williams makes a very interesting thought experiment. He asks what fraction of the transportation fuels for North America can his coal/biomass/sequestration route provide. The answer is that all fuels estimated to be required by 2050 for transportation of all sorts could be produced from the estimated 1.3 B tones per year of biomass potentially available on a sustainable basis as estimated by DOE and USDA. This resource includes agricultural and forest residues and municipal waste as well as biomass energy crops. The latter provides only about 30% of the total resource. This can only be accomplished, however, if the light duty vehicle fleet has an average fuel efficiency of 60 mpg or greater by 2050, not an impossible target. Also, such a synfuels enterprise would double current use of coal.

This is a rough summary of Bob Williams great idea. I understand that he will submit written testimony to the Committee to supply details. He has done very elaborate and detailed calculations for many variations on his theme.

Finally, here is a set of policies suggested by Williams that I believe could encourage innovation in developing solutions to the coupled problems of oil security and climate change mitigation. The policies are designed to be largely technology independent to avoid picking winners.

First, the greenhouse gas emission externality must be reduced by putting a cost on emissions by cap and trade or tax or whatever. The Congress through various pieces of legislation is actively considering this, and no doubt something will emerge.

Second, a low-carbon fuel standard such as is being developed by the State of California should be adopted and existing subsidies on low carbon fuels should be discontinued.

Third, regulations should be adopted to assure that no new coal synfuels plants are built without carbon capture and storage.

Fourth, an oil security feebate might be enacted to put a floor on transportation fuel prices. If oil prices crash, say to $30/bbl from $60, transportation fuel could be taxed and part of the tax rebated to synfuels plants to help them compete and produce even with low world oil prices. Part of the tax revenues could be returned to the public.

Fifth, regulations (such as improved CAFE standards) to promote more efficient use of transportation fuels need to be aggressively strengthened over time.

Sixth, regulations and R&D to improve coalmine safety, worker health, and environmental improvement need to be periodically reviewed and upgraded if necessary.

Of course it is easy to make such a list. The hard work comes in sorting out the many options so policies are effective, fair and politically possible. I think that is your job, and it is a difficult one.

The CHAIRMAN. Thank you very much for your testimony.

Mr. Bartis, go right ahead.

STATEMENT OF JAMES BARTIS, SENIOR POLICY RESEARCHER, RAND CORPORATION, ARLINGTON, VA

Mr. BARTIS. Mr. Chairman and distinguished members, thank you for inviting me to testify. My remarks today are based on RAND research, some of which is ongoing, sponsored by the National Energy Technology Laboratory, the United States Air Force, the Federal Aviation Administration, and the National Commission on Energy Policy.

Congress has before it the two major energy challenges: first, what to do about large well transfers from oil consumers to OPEC; and second, how can we reduce our greenhouse gas emissions?

OPEC revenues from oil exports are currently about $500 billion per year, and are heading higher. These high revenues raise serious national security concerns because some of the OPEC member states are governed by regimes that are not supportive of U.S. foreign policy objectives. Oil revenues have been, and are being, used to purchase weapons. Moreover, the higher oil prices rise, the greater the chances that oil importing countries will pursue special relationships with oil exporters and defer joining the United States in multilateral diplomatic efforts. We see this happening right now in South America and Africa.

No less pressing is the importance of addressing the threat of global climate change. For example, as you just heard, without measures to address carbon dioxide emissions, the use of coal-derived liquids to displace petroleum fuels for transportation will roughly double greenhouse gas emissions. This is clearly not acceptable.

The emphasis of RAND's research on unconventional fuels has been on these two potentially conflicting policy objectives. We have concentrated our efforts on coal-to-liquids because that option is one of the only two approaches that are commercially ready and capable of displacing significant amounts of imported petroleum. The only other technical option that meets these criteria is ethanol production from food crops. Moreover, only the coal-to-liquids approach produces a fuel suitable for use in heavy-duty trucks, railroad engines, commercial aircraft, or military vehicles and weapons systems.

When we look to the future, the only near-term, low-risk option beyond the two I just mentioned is a variance of the same technology that is used for producing liquids from coal; namely, gasification, in Fischer-Tropsch synthesis, as applied to biomass, such as crop residues or a combination of biomass and coal, as just discussed by Mr. Fulkerson.

Producing large amounts of coal-derived liquid fuels will cause world oil prices to decrease. Our research shows that, under reasonable assumptions, this price reduction effect could be very large and would likely result in large benefits to U.S. consumers and large decreases in OPEC revenues. Savings by the average household in the United States would range from a few hundred to a few thousand dollars per year. OPEC export revenues could decrease by hundreds of billions of dollars per year.

We also examined whether a coal-to-liquids industry can be developed consistent with the need to manage carbon dioxide emissions. If we are willing to accept emission levels that are similar to those associated with conventional petroleum, the answer is definitely yes.

Two technical approaches are available that allow this level of control: the first involves the capture and geological sequestration of carbon dioxide at the plant site. This approach appears feasible, but it has not been proven, and it will not be proven until multiple large-scale demonstrations are successfully conducted, and fortunately, the second approach is a very low-risk approach; namely, using a combination of coal and biomass, as you just heard, in a Fischer-Tropsch plant. Now, given the large demand on OPEC oil that we anticipate over the next 50 years, this is a great answer. We can at least address a major economic and national security problem while not worsening environmental impacts.

If, however, we demand a significant reduction in emission levels, as compared to conventional petroleum, the answer is a qualified yes. The only way we know of reaching this level of carbon dioxide control when making coal-derived liquids is to use the combination of coal and biomass, and to capture and sequester most of the carbon dioxide generated at the plant site. The reason I give a qualified yes is that there does remain considerable uncertainty regarding the viability of sequestering carbon dioxide in geological formations.

Stepping back a bit, we have, at RAND, reviewed the prospects of coal-to-liquids production in the United States, and we see three major uncertainties that are impeding private-sector investment.

The first uncertainty centers on the cost and performance of coal-to-liquid plants. Our current best estimate is that coal-to-liquids production is not competitive unless crude oil prices are in the range of $50 to $60 per barrel. However, this estimate is based on highly conceptual engineering designs that are only intended to provide a rough estimate of costs. At RAND, we have learned that, when it comes to cost estimates, it is often the case that the less you know, the more attractive the course.

The second uncertainty concerns the future direction of world oil prices. The third uncertainty, I've already touched upon is namely, whether, and how greenhouse gas emissions might be controlled in the United States.

Just as these three uncertainties are impeding private sector investment, they should also deter an immediate national commitment to rapidly put in place a multimillion-barrel-per-day coal-to-liquids industry. However, the traditional hands-off, or research-only, approach is not commensurate with the continuing adverse economic, national security, and global environmental consequences of relying on imported petroleum. For these reasons, Congress should consider a middle path that focuses on reducing uncertainties and fostering early commercial experience by: No. 1, providing Federal cost-sharing of front-end engineering designs for a few commercial plants; and No. 2, promoting the construction and operations of a limited number of commercial-scale plants by establishing a flexible incentive program capable of attracting the participation of America's top technology firms. We characterize this middle path as an insurance strategy, since, for modest payments, it significantly improves the ability of the private sector to respond officially to future market developments as both government and industry learn more about the future course of world oil prices and as the policy and technical mechanisms for carbon management become clearer.

Thank you very much.

[The prepared statement of Mr. Bartis follows:]

PREPARED STATEMENT OF JAMES T. BARTIS,[1] SENIOR POLICY RESEARCHER, RAND CORPORATION, ARLINGTON, VA

POLICY ISSUES FOR COAL-TO-LIQUID DEVELOPMENT[2]

Chairman and distinguished Members: Thank you for inviting me to speak on the potential use of our nation's coal resources to produce liquid fuels. I am a Senior Policy Researcher at the RAND Corporation with over 25 years of experience in ana-

[1] The opinions and conclusions expressed in this testimony are the author's alone and should not be interpreted as representing those of RAND or any of the sponsors of its research. This product is part of the RAND Corporation testimony series. RAND testimonies record testimony presented by RAND associates to federal, state, or local legislative committees; government-appointed commissions and panels; and private review and oversight bodies. The RAND Corporation is a nonprofit research organization providing objective analysis and effective solutions that address the challenges facing the public and private sectors around the world. RAND's publications do not necessarily reflect the opinions of its research clients and sponsors.

[2] This testimony is available for free download at http://www.rand.org/pubs/testimonies/CT281.

lyzing and assessing energy technology and policy issues. At RAND, I am actively involved in research directed at understanding the costs and benefits associated with alternative approaches for promoting the use of coal and other domestically abundant resources, such as oil shale and biomass, to lessen our nation's dependence on imported petroleum. Various aspects of this work are sponsored and funded by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy, the United States Air Force, the Federal Aviation Administration, and the National Commission on Energy Policy.

Today, I will discuss the key problems and policy issues associated with developing a domestic coal-to-liquids industry and the approaches Congress can take to address these issues. My key conclusions are as follows. First, successfully developing a coal-to-liquids industry in the United States would bring significant economic and national security benefits by reducing wealth transfers to oil-exporting nations. Second, the production of petroleum substitutes from coal may cause a significant increase in carbon dioxide emissions; however, technical approaches exist that could lower carbon dioxide emissions to levels well below those associated with producing and using conventional petroleum. Third, without federal assistance, private-sector investment in coal-toliquids production plants is unlikely to occur, because of uncertainties about the future of world oil prices, the costs and performance of initial commercial plants, and the viability of carbon management options. Finally, a federal program directed at reducing these uncertainties and obtaining early, but limited, commercial experience appears to offer the greatest strategic benefits, given both economic and national security benefits and the uncertainties associated witheconomic viability and environmental performance, most notably the control of greenhouse gas emissions.

Some of the topics I will be discussing today are supported by research that RAND has only recently completed; consequently, the results have not yet undergone the thorough internal and peer reviews that typify RAND research reports. Out of respect for this Committee and the sponsors of this research, and in compliance with RAND's core values, I will only present findings in which RAND and I have full confidence at this time.

Coal Gasification and Liquid Fuels Production

There are two major approaches for using coal to produce liquid transportation fuels: direct liquefaction and the Fischer–Tropsch (F-T) processes. Both processes were developed in pre-World War II Germany and both were used, but on fairly small scales, to meet Germany's and Japan's wartime needs for fuel. In the direct liquefaction approach, hydrogen is added directly to the organic structure of coal at high pressures and temperatures. At present, a large first-of-a-kind commercial plant based on direct liquefaction is being built in China. Pending the completion and successful operation of that plant, we do not anticipate that there will be industrial interest in the direct liquefaction approach within the United States. For this reason, I will confine my remarks to the F-T process, which is the focus of considerable industrial interest in the United States.

In the F-T approach, coal is first gasified to produce a mixture that consists mostly of three gases: carbon monoxide, hydrogen, and carbon dioxide. This gas mixture is further processed to remove carbon dioxide, as well as trace contaminants, and the resulting mixture of clean hydrogen and carbon monoxide is sent to a chemical reactor where the gaseous mixture is catalytically converted to liquid products. After a moderate amount of fuel processing that would be performed on-site, a commercial F-T plant would produce a near-zero sulfur, high-performance diesel fuel for automotive applications and a near-zero sulfur jet fuel that can be used for commercial aviation applications or in military weapon systems. Between a third and one half of the product of commercial F-T coal-to-liquid plants would be a mixture of liquids that can be used to manufacture motor gasoline, either at the F-T plant site or at nearby refineries.

Since the end of World War II, the only commercial experience in F-T coal-to-liquids production has occurred in South Africa under government subsidy. In particular, a South African plant constructed in the early 1980s currently produces fuels and chemicals that are the energy equivalent of about 160,000 barrels per day of oil.

An interesting feature of the F-T approach to liquid fuels production is that it is not limited to coal. For example, large commercial F-T plants producing liquid fuels from natural gas are operating in Malaysia, Qatar, and South Africa. Other options are to use biomass or a combination of coal and biomass as the feedstock instead of straight coal. While these options are not being used on acommercial scale, our assessment of approaches using biomass or a combination of coal and biomass is that they involve very limited, low-risk technology development. As I elaborate on below, these two approaches involving biomass offer liquid fuels production and use that entail near-zero emissions of carbon dioxide.

Technical Readiness and Production Potential

As part of RAND's examination of coal-to-liquids fuels development, we have reviewed the technical, economic, and environmental viability and production potential of a range of options for producing liquid fuels from domestic resources. If we focus on unconventional fuel technologies that are now ready for large-scale commercial production and that can displace at least a million barrels per day of imported oil, we find only two candidates: grain-derived ethanol and F-T coal-toliquids. Moreover, only the F-T coal-to-liquids candidate produces a fuel that is suitable for use in heavy-duty trucks, railroad engines, commercial aircraft, or military vehicles and weapon systems. If we expand our time horizon to consider technologies that might be ready for use in initial commercial plants within the next five years, only one or two new technologies become available: the in-situ oil shale approaches being pursued by a number of firms and the F-T approaches for converting biomass or a combination of coal and biomass to liquid fuels. We have also looked carefully at the development prospects for technologies that offer to produce alcohol fuels from sources other than food crops, so-called cellulosic materials. Our finding is that while this is an important area for research and development, the technology base is not yet sufficiently developed to support an assessment that alcohol production from cellulosic materials will be competitive with F-T biomass-to-liquid fuels within the next ten years, if ever.

The Strategic Benefits of Coal-to-Liquids Production

As part of RAND's examination of coal-to-liquid fuels development, our research is addressing the strategic benefits of having in place a mature coal-to-liquid fuels industry producing millions of barrels of oil per day. If coal-derived liquids were added to the world oil market, such liquids would cause world oil prices to be lower than what would be the case if they were not produced. This effect occurs regardless of what fuel is being considered. It holds for coal-derived liquids and for oil shale, heavy oils, tar sands, and biomass-derived liquids, as well as, for that matter, additional supplies of conventional petroleum. The price reduction effect also occurs when oil demand is reduced through fiscal measures, such as taxes on oil, or through the introduction of advanced technologies that use less petroleum, such as higher mileage vehicles. Moreover, this reduction in world oil prices is independent of where such additional production or energy conservation occurs, as long as the additional production is outside of OPEC and OPEC-cooperating nations.

In a 2005 analysis of the strategic benefits of oil shale development, RAND estimated that 3 million barrels per day of additional liquid fuels production would yield a world oil price drop of between 3 and 5 percent.[3] Our ongoing research supports that estimated range and shows that the price drop increases in proportion to production increases. For instance, an increase of 6 million barrels per day would likely yield a world oil price drop of between 6 and 10 percent. This more recent research also shows that even larger price reductions may occur in situations in which oil markets are particularly tight or in which OPEC is unable to enforce a profit-optimizing response among its members.

This anticipated reduction in world oil prices yields important economic benefits. In particular, American consumers would pay tens of billions of dollars less for oil or, under some future situations, hundreds of billions of dollars less for oil per year. On a per-household basis, we estimate that the average annual benefit would range from a few hundred to a few thousand dollars.

This anticipated reduction in world oil prices associated with coal-to-liquids development also yields a major national security benefit. At present, OPEC revenues from oil exports are about $500 billion per year. Projections of future petroleum supply and demand published by the Department of Energy indicate that unless measures are taken to reduce the prices of, and demand for, OPEC petroleum, such revenues will grow considerably. These high revenues raise serious national security concerns, because some OPEC member nations are governed by regimes that are not supportive of U.S. foreign policy objectives. Income from petroleum exports has been used by unfriendly nations, such as Iran and Iraq under Saddam Hussein, to support weapons purchases, or to develop their own industrial base for munitions manufacture. Also, the higher prices rise, the greater the chances that oil-importing countries will pursue special relationships with oil exporters and defer joining the United States in multilateral diplomatic efforts.

[3] Oil Shale Development in the United States: Prospects and Policy Issues, Santa Monica, CA: RAND MG414-NETL, 2005.

Our research shows that developing an unconventional fuels industry that displaces millions of barrels of petroleum per day will cause a significant decrease in OPEC revenues from oil exports. This decrease results from a combination of lower prices and a lower demand for OPEC production. The size of this reduction in OPEC revenues is determined by the volume of unconventional fuels produced and future market conditions, but our ongoing research indicates that annual reductions of hundreds of billions of dollars are not unreasonable. The significant reduction in wealth transfers to OPEC and the geopolitical consequences of reduced demand for OPEC oil represent the major national security benefits associated with the development of an unconventional liquid fuels production industry.

The above-described strategic benefits derive from the existence of the OPEC cartel. The favorable benefits of reduced oil prices accrue to our nation as a whole; however, they are not captured by the private firms that would invest in coal-to-liquids development.

The Direct Benefits of Coal-to-Liquids Production

Beyond the strategic benefits for the nation associated with coal-to-liquids production are certain direct benefits. If coal-derived liquid fuels can be produced at prices well below world oil prices, then the private firms that invest in coal-derived liquid fuels development could garner economic profits above and beyond what is considered a normal return on their investments. Through taxes on these profits and, in some cases, lease and royalty payments, we estimate that roughly 35 percent of these economic profits could go to federal, state, and local governments and, thereby, broadly benefit the public.

A second direct benefit derives from the broad regional dispersion of the U.S. coal resource base and the fact that coal-to-liquids plants are able to produce finished motor fuel products that are ready for retail distribution. As such, developing a coal-to-liquids industry should increase the resiliency of the overall petroleum supply chain.

The remaining direct benefits of developing a coal-to-liquids production industry are local or regional, as opposed to national. In particular, coal-to-liquids industrial development offers significant opportunities for economic development and would increase employment in coal-rich states.

Greenhouse Gas Emissions

Given the Committee's interest in greenhouse gas emissions, I limit my remarks to that topic and simply point out that the environmental impacts associated with certain types of coal mining and water usage requirements, especially in the West, may limit the number of locations at which F-T coal-to-liquid plants can be operated.

If no provisions are in place to manage carbon dioxide emissions, then the use of F-T coal-toliquids fuels to displace petroleum fuels for transportation uses will roughly double greenhouse gas emissions. This finding is relevant to the total fuel lifecycle, i.e., well-to-wheels or coal-mine-to-wheels. This increase in greenhouse gas emissions is primarily attributable to the large amount of carbon dioxide emissions that come from a F-T coal-to-liquids production plant relative to a conventional oil refinery. In fact, looking solely at the combustion of F-T derived fuel as opposed to its production, our analyses show that combustion of an F-T coal-derived fuel would produce somewhat, although not significantly, lower greenhouse gas emissions relative to the combustion of a gasoline or diesel motor fuel prepared by refining petroleum.

In our judgment, the high greenhouse gas emissions of F-T coal-to-liquids plants that do not manage such emissions preclude their widespread use as a means of displacing imported petroleum. We now turn to some options for managing greenhouse gas emissions.

Options for Managing Greenhouse Gas Emissions

For managing greenhouse gas emissions for F-T coal-to-liquid plants, RAND examined three options: (1) carbon capture and sequestration, (2) carbon dioxide capture and use in enhanced oil recovery, and (3) gasification of both coal and biomass followed by F-T synthesis of liquid fuels. We discuss each below in turn.

Carbon Capture and Sequestration.—By carbon capture and sequestration, I refer to technical approaches being developed in the United States, primarily through funding from the U.S. Department of Energy, and abroad that are designed to capture carbon dioxide produced in coal-fired power plants and sequester that carbon dioxide in various types of geological formations, such as deep saline aquifers. This same approach can be used to capture and sequester carbon dioxide emissions from F-T coal-to-liquids plants and from F-T plants operating on biomass or a combination of coal and biomass. When applied to F-T coal-to-liquids plants, carbon capture and sequestration should cause "mine-to-wheels" greenhouse gas emissions to drop to levels comparable to the "well-to-wheels" emissions associated with conventional petroleum-derived motor fuels. Moreover, any incentive adequate to promote carbon capture at coal-fired power plants should be equally, if not more, effective in promoting carbon capture at F-T plants producing liquid fuels.

The U.S. Department of Energy program on carbon capture and sequestration appears to be well managed and has made considerable technical progress. However, considering the continued and growing importance of coal for both power and liquids production and the potential adverse impacts of greenhouse gas emissions, we believe this program has been considerably underfunded. While we are optimistic that carbon capture and geologic sequestration can be successfully developed as a viable approach for carbon management, we also recognize that successful development constitutes a major technical challenge and that the road to success requires multiple, large-scale demonstrations that go well beyond the current DOE plans and budget for the efforts that are now under way.

Carbon Capture and Enhanced Oil Recovery.—In coal-to-liquids plants, about 0.8 tons of carbon dioxide are produced along with each barrel of liquid fuel. For coal-to-liquids plants located near currently producing oil fields, this carbon dioxide can be used to drive additional oil recovery. We anticipate that each ton of carbon dioxide applied to enhanced oil recovery will cause the additional production of 2 to 3 barrels of oil, although this ratio depends highly on reservoir properties and oil prices. Based on recent studies sponsored by the U.S. Department of Energy, opportunities for enhanced oil recovery provide carbon management options for at least a half million barrels per year of coal-to-liquids production capacity. A favorable collateral consequence of this approach to carbon management is that a half million barrels per day of coal-to-liquids production will promote additional domestic petroleum production of roughly 1 million barrels per day.

The use of pressurized carbon dioxide for enhanced oil recovery is a well-established practice in the petroleum industry. Technology for capturing carbon dioxide at a coal-to-liquids plant is also well established. There are no technical risks, but questions do remain about methods to optimize the fraction of carbon dioxide that would be permanently sequestered.

Combined Gasification of Coal and Biomass.—Non-food crop biomass resources suitable as feedstocks for F-T biomass-to-liquid production plants include mixed prairie grasses, switch grass, corn stover and other crop residues, forest residues, and crops that might be grown on dedicated energy plantations. When such biomass resources are used to produce liquids through the F-T method, our research shows that greenhouse gas emissions should be well below those associated with the use of conventional petroleum fuels. Moreover, when a combination of coal and biomass is used, for example, a 50-50 mix, we estimate that net carbon dioxide emissions will be comparable to or, more likely, lower than well-to-wheels emissions of conventional petroleum-derived motor fuels. Finally, we have examined liquid fuel production concepts in which carbon capture and sequestration is combined with the combined gasification of coal and biomass. Our preliminary estimate is that a 50-50 coal-biomass mix combined with carbon capture and sequestration should yield zero, and possibly negative, carbon dioxide emissions. In the case of negative emissions, the net result of producing and using the fuel would be the removal of carbon dioxide from the atmosphere.

One perspective on the combined gasification of coal and biomass is that biomass enables F-T coal-to-liquids, in that the combined feedstock approach provides an immediate pathway to unconventional liquids with no net increase in greenhouse gas emissions, and an ultimate vision, with carbon capture and sequestration, of zero net emissions. Another perspective is that coal enables F-T biomass-to-liquids, in that the combined approach reduces overall production costs by reducing fuel delivery costs, allowing larger plants that take advantage of economies of scale, and smoothing over the inevitable fluctuations in biomass availability associated with annual and multi-year fluctuations in weather patterns, especially rainfall.

Prospects for a Commercial Coal-to-Liquids Industry

The prospects for a commercial coal-to-liquids industry in the United States remain unclear. Three major impediments block the way forward:

1. Uncertainty about the costs and performance of coal-to-liquids plants;
2. Uncertainty about the future course of world oil prices;
3. Uncertainty about whether and how greenhouse gas emissions, especially carbon dioxide emissions, might be controlled in the United States.

As part of our ongoing work, RAND researchers have met with a number of firms that are promoting coal-to-liquids development or that clearly have the management, financial, and technical capabilities to play a leading role in developing of a commercial industry. Our findings are that the three uncertainties noted above are impeding and will continue to impede private-sector investment in a coal-to-liquids industry unless the government provides fairly significant financial incentives, especially incentives that mitigate the risks of a fall in world oil prices.

But just as these three uncertainties are impeding private-sector investment, they should also deter an immediate national commitment to establish rapidly a multi-million-barrel-per-day coal-to-liquids industry. However, the traditional hands-off or "research only" approach is not commensurate with continuing adverse economic, national security, and global environmental consequences of relying on imported petroleum. For this reason, Congress should consider a middle path to developing a coal-to-liquids industry, which focuses on reducing uncertainties and fostering early operating experience by promoting the construction and operation of a limited number of commercial-scale plants. We consider this approach an "insurance strategy," in that it is an affordable approach that significantly improves the national capability to build a domestic unconventional fuels industry as government and industry learn more about the future course of world oil prices and as the policy and technical mechanisms for carbon management become clearer.

Designing, building, and gaining early operating experience from a few coal-to-liquids plants would reduce the cost and performance uncertainties that currently impede private-sector investments. At present, the knowledge base for coal-to-liquid plant construction costs and environmental performance is very limited. Our current best estimate is that coal-to-liquids production from large first-of-a-kind commercial plants is competitive when crude oil prices average in the range of $50 to $60 per barrel. However, this estimate is based on highly conceptual engineering design analyses that are only intended to provide a rough estimate of costs. At RAND, we have learned that, when it comes to cost estimates, typically the less you know, the more attractive the costs. Details are important, and they are not yet available. For this reason, we believe that it is essential that the Department of Energy and Congress have access to the more reliable costing that is generally associated with the completion of a front-end engineering design.

Early operating experience would promote post-production learning, leading to future plants with lower costs and improved performance. Post-production cost improvement—sometimes called the learning curve—plays a crucial role in the chemical process industry, and we anticipate that this effect will eventually result in a major reduction of the costs of coal-derived liquid fuels. Most important, by reducing cost and performance uncertainties and production costs, a small number of early plants could form the basis of a rapid expansion of a more economically competitive coalto-liquids industry, depending on future developments in world oil markets.

Options for Federal Action

The Federal government could take several productive measures to address the three major uncertainties noted above—production risks, market risks, and global warming—so that industry can move forward with a limited commercial production program consistent with an insurance strategy. A key step, as noted above, is reducing uncertainties about plant costs and performance by encouraging the design, construction, and operation of a few coal-to-liquid plants. An engineering design adequate to obtain a confident estimate of costs, to establish environmental performance, and to support federal, state, and local permitting requirements will cost roughly $30 million. The Federal government should consider cost-sharing options that would promote the development of a few site-specific designs. The information from such efforts would also provide Congress with a much stronger basis for designing broader measures to promote unconventional fuel development.

At present, RAND is analyzing alternative incentive packages for promoting early commercial operating experience. In this analysis of incentives, we are examining not only the extent that the incentive motivates private-sector investment but also the potential impact on federal expenditures over a broad range of potential future outcomes. At this time, we are able to report that more attractive incentive packages generally involve a combination of the following three mechanisms: (1) a reduction in front-end investment costs, such as what would be offered by an investment tax credit; (2) a reduction in downside risks by a floor price guarantee; and (3) a sharing of upside benefits such as what would be offered by a profit sharing agreement between the government and producers when oil prices are high enough to justify such sharing. We also caution against the use of federal loan guarantees. Firms with the technical and management wherewithal to build and operate first-of-a-kind coal-to-liquids plants—and then move forward with subsequent plants—generally have access to needed financial resources. Loan guarantees can induce the participation of less capable firms, while isolating the project developer from the risks associated with cost overruns and shortfalls in plant performance. The public then ends up absorbing the costs if the project fails.

Given the importance of controlling greenhouse gas emissions, it is appropriate that Congress demand that the initial round of commercial plants receiving government incentives employ carbon management approaches so that net greenhouse gas emissions are at least comparable to those anticipated from refining and using motor fuels derived from conventional petroleum.

If the Federal government is prepared to promote early production experience, then expanded federal efforts in other areas would also be needed. Most important, consideration should be given to accelerating the development and testing (including large-scale testing) of methods for the longterm sequestration of carbon dioxide. This could involve using one or more of the early coal-to-liquids production plants as a source of carbon dioxide for the testing of sequestration options.

At present, federal support for research on F-T approaches for liquids production is minimal. A near-term technology development effort designed to establish the commercial viability of a few techniques for the combined use of coal and biomass in a F-T liquids facility could offer significant cost and environmental payoffs. In promoting the production of alcohol fuels from cellulosic feedstocks, the federal government is making major R&D investments. In our judgment, the appropriate approach to balance this fuels production portfolio is not to lower the investment in cellulosic conversion, but rather to significantly increase the investment in F-T approaches, including coal, biomass, and combined coal and biomass gasification. This research investment should also include high-risk, high-payoff opportunities for cost reduction and improved environmental performance. Such efforts would significantly enhance the learning/cost reduction potential associated with early production experience. Such longer-term research efforts would also support the training of specialized scientific and engineering talent required for long-term progress.

In closing, I commend the Committee for addressing the important and intertwined topics of reducing demand for crude oil and reducing greenhouse gas emissions. The United States has before it many opportunities—including coal and oil shale, renewables, improved energy efficiency, and fiscal and regulatory actions—that can promote greater energy security. Coal-to-liquids and more generally F-T gasification processes can be important parts of the portfolio as the nation responds to the realities of world energy markets, the presence of growing energy demand, and the need to protect the environment.

The CHAIRMAN. Thank you very much.

Mr. Denton, go right ahead.

STATEMENT OF DAVID DENTON, DIRECTOR, BUSINESS DEVELOPMENT, EASTMAN GASIFICATION SERVICES COMPANY, KINGSPORT, TN

Mr. DENTON. Mr. Chairman and distinguished members of the Committee, thank you for inviting Eastman Chemical Company to share its views regarding the opportunities and challenges of industrial gasification, meaning the gasification driving production of industrial chemicals or products.

I'm David Denton, director of business development for Eastman Gasification Services Company, a wholly owned subsidiary of Eastman Chemical Company. I'm a chemical engineer by profession, have worked in a number of technical and management positions within Eastman's research and technology organizations for the past 32 years. I also hold the title of technology fellow within Eastman.

In my present position, I identify and develop customers and project opportunities for our gasification business, and coordinate the public policy and technology initiatives.

My company, Eastman Chemical, manufactures and markets chemicals, fibers, and plastics worldwide. We were founded in 1920, headquartered in Kingsport, Tennessee. We're a Fortune 500 company with 2006 sales of $7.5 billion, and approximately 11,000 employees. Approximately 7,000 of those are employed in Senator

Corker's State, and another 2,600 are located elsewhere in the United States. We are a U.S. company.

The chemicals industry, as a whole, employs nearly 900,000 people in the United States in high-paying jobs. There are an additional 4.5 million jobs in the chemical industry supply chain and services industries.

Natural gas is the key feedstock for the production of most chemicals. Unfortunately, the rapid increase in natural gas prices this decade puts the majority of domestic chemical industry jobs at great risk. To put the price increase in perspective, natural gas prices have risen 41 percent more than gasoline prices since the year 2000. We all know how much gasoline has risen. The NYMEX price for January delivery is 35 percent higher than today's price for natural gas.

Electric generation has surpassed the chemical industry this decade as the largest consumer of natural gas. Natural gas use in electric generation has increased by 75 percent over the past 10 years, and now accounts for 27 percent of all electric generation, more than nuclear.

Environmental considerations, particularly greenhouse gas reduction, will inevitably drive natural gas demand and prices even higher in the future. These rising natural gas prices ripple through the economy. Chemicals, food, packaging, steel, glass, all cost more when natural gas prices go up and jobs in these industries decline. In the ammonia-based fertilizer industry, for example, 50 percent of our jobs have been lost this decade to countries with lower natural gas cost components, countries such as Russia and those in the Middle East.

The committee should do all it can to increase natural gas supplies in an environmentally sustainable way. Under any circumstances, however, the United States must move to develop substitutes for natural gas from domestic resources that are clean, inexpensive, plentiful, readily available, and secure.

Eastman has extensive experience developing and using just such a substitute, and that is gasified coal. We pioneered the first commercial U.S. chemicals-from-coal facility in 1983 at our site in Kingsport, Tennessee. Our east coal gasification operating performance is industry-leading and highly regarded worldwide. Our forced outage rate has averaged less than 2 percent since initial startup. This availability record of greater than 98 percent for over two decades of operation is exceptional for any coal-fed facility. Today, Eastman operates its gas fires with the highest syngas output per unit volume of any GE syn-gasifier in the world, and has over 600 person-years of combined operating experience in coal gasification. We're confident enough in coal gasification and its ability to develop high-valued products that in November of last year our chairman and CEO, Brian Ferguson, announced to the financial markets that we intend to drive at least 50 percent of our product volume from coal or feedstock within the next 10 years.

Gasification, particularly industrial gasification of coal and other feedstocks, presents great opportunities for reduced natural gas demand, and, consequently, to reduce prices for all domestic consumers. The potential benefits for U.S. jobs preservation, our economy, trade balance, energy security, and the environment are tremendous. Our gasification is a very general term. It's not a single technology. There are many different gasifiers and gasification concepts.

There are fundamental differences between gasification technology systems suitable for industrial gasification applications and those suitable for standalone power generation, or IGCC. These differences have significant implications for total system efficiencies and for the readiness to separate carbon from other constituents in the syngas stream.

Industrial-based gasification systems, such as Eastman's facility, are designed, inherently and specifically, to capture carbon as part of their product stream. Typically, over 90 percent of any CO_2 in an industrial synthesis gas stream is captured because downstream process steps require it. The cost of this capture is thus included in the price of the final industrial products. This is unlike industrial gasification processes. Gasifiers designed for power generation do not currently separate CO_2 or carbon from the syngas stream because there is no current economic reason or process requirements to do so. I believe that carbon capture for these power systems will be economically acceptable in the future, driven by market forces, R&D improvements, and regulatory requirements, but IGCC systems today don't have the ability and the equipment to capture CO_2, as do industrial gasifiers.

In my written statement, I've identified a number of unique characteristics of industrial gasification processes that inherently enable or advantage high levels of carbon capture. In addition to these technology distinctions, much of America's chemical industry infrastructure is located in, or near, geographic regions where carbon sequestration may present a win-win opportunity with enhanced oil recovery.

So, industrial gasification systems prevent real and high-value opportunities with respect to carbon capture and geologic sequestration.

At the risk of using an overworked phrase, industrial gasification represents the low-hanging fruit, as the Congress and administration consider a program to test and develop carbon capture and sequestration technologies, protocols, regulations, and financing issues in commercial settings.

Industrial gasification opportunities represent the logical economic and technological path forward to achieve four policy objectives I believe are key to America's economic and environmental health. Those are cost-effective environmental protection, energy security through the reliance on domestic fuel resources, reduction of natural gas prices and price volatility to all consumers, and global competitiveness and the preservation and expansion of millions of high-technology jobs in America's industrial sector.

As promising as industrial gasification is for the policy objectives above, deployment of commercial plants will not occur, and the proving ground for carbon capture and sequestration will not be available, unless Federal and State governments provide the necessary incentives and framework to attract these first-adopter projects.

As the MIT future coal study correctly points out, in our view, similar incentives, such as production tax credits, should be applied to carbon capture and geologic sequestration. There are considerable market, legal, and regulatory hurdles to be overcome or addressed before these first-adopters can attempt carbon sequestration, particularly in deep saline aquifers. However, doing so now could have significant benefits for the entire Nation.

Federal incentives necessary to stimulate carbon capture and sequestration will be expensive, but, by paying for much of the cost of carbon capture in the price of its products, leading primarily carbon dioxide compression and sequestration costs to be incentivized, industrial gasification can provide the lowest cost and quickest route to for incentivizing and implementing such commercial demonstrations.

Thank you for the opportunity to share Eastman's views on the opportunities and challenges associated with industrial gasification.

[The prepared statement of Mr. Denton follows:]

PREPARED STATEMENT OF DAVID DENTON, DIRECTOR, BUSINESS DEVELOPMENT, EASTMAN GASIFICATION SERVICES COMPANY, KINGSPORT, TN

Mr. Chairman, members of the committee, I am David Denton, Business Development Director for Eastman Gasification Services Company, a wholly-owned subsidiary of Eastman Chemical Company. I am a chemical engineer and registered professional engineer. I am a Technology Fellow within Eastman. In my present position, I identify and develop customers and project opportunities for Eastman's gasification business, and coordinate with public policy and technology initiatives. Over my 32 years experience with Eastman Chemical Company I have worked in a number of technical and management positions within Eastman's Research and Technology organizations.

INTRODUCTION TO EASTMAN

Eastman Chemical Company manufactures and markets chemicals, fibers and plastics worldwide. It provides key differentiated coatings, and adhesives and specialty products; is the world's largest producer of PET polymers for packaging; and is a major supplier of cellulose acetate fibers. Founded in 1920 and headquartered in Kingsport, Tennessee, Eastman is a FORTUNE 500 company with 2006 sales of $7.5 billion and approximately 11,000 employees. Approximately 7,000 of those are employed in Senator Corker's state and another 2,600 are located elsewhere in the United States. For more information about Eastman, and its products, visit www.eastman.com.

EASTMAN AND GASIFICATION

Eastman was a pioneer in commercializing the first U.S. chemicals from coal facility in 1983. Eastman received Chemical Engineering magazine's Kirkpatrick Award for Engineering Excellence for recognition of its "chemicals from coal" facility in Kingsport, Tennessee, and the facility has been designated an American Chemical Society National Historic Chemical Landmark.

Eastman's coal gasification operating performance is industry-leading and is highly regarded world wide. The first full year of operation (1984), Eastman's forced outage rate was between 8% and 9% and has averaged less than 2% ever since. Forced outage rate for the past full three year maintenance cycle was 1.06%, and the gasification facility was on-stream over 98% of the time.

Eastman has a strong commitment to process improvement and has continually improved and optimized its gasification operations over time. Today, Eastman operates its coal gasifiers at the highest syngas output per unit gasifier volume of any GE Energy designed solids-fed gasifier in the world. In addition, Eastman has built a tremendous support infrastructure for gasification during the past two decades. Some examples of that support infrastructure include:

- A large data base of equipment reliability data and root cause failure analyses
- Gasification modeling and simulation
- Advanced process control systems
- Process instrumentation and analysis (including on-line analyses)

- Refractory design, inspection, and installation services
- Reliability-based predictive maintenance systems
- Coal, petcoke, and slag chemistry and characterization
- Optimized standard operating procedures
- Rapid gasifier start-up and switch-over procedures
- Multiple gasifier operation and integration experience
- Specialized materials science and metallurgy
- A large code-rated machine shop for critical parts fabrication and repair
- Proven environmental and safety systems and procedures

Eastman's technical, operations, and support staff have over 600 years of combined experience in coal gasification, an experience base which is unrivaled in the chemical industry. In addition to experience with Eastman's gasifiers, Eastman has made selective hires of gasification experts with broad experience at other companies and facilities. Eastman engineers have had direct experience with start-up, trouble-shooting, and/or operations at over 20 gasification facilities around the world, including a number of petcoke and coal-fed gasifiers.

In addition to gasification expertise, Eastman and its subsidiaries have over 80 years of experience in managing large integrated manufacturing sites. Eastman owns and operates a number of large integrated plant sites in the U.S. and overseas. Eastman's largest site in Kingsport, Tennessee, has over 7,000 employees and manufactures hundreds of products.

Eastman has also developed an extensive and respected expertise in the management, execution, and commissioning of major capital projects. In external benchmarking studies, Eastman was recognized for top quintile performance in overall capital cost, schedule performance, and overall capital effectiveness, as well as being ranked best-in-class in several areas.

OPPORTUNITIES

My testimony today will focus on technology "opportunities and challenges" of gasification, particularly industrial gasification, and on technical and institutional issues related to the potential for carbon capture and geologic sequestration (CCGS).

As we begin to talk about "gasification," I want to emphasis that this is a very general term. Gasification is not a single technology; there are as many different gasifiers and gasification concepts as there are members of this Committee, actually more. The choice of gasifiers and technical systems approach for a given project depends on many factors, principal of which are the intended product and the intended feedstock.

There are fundamental differences between gasification technology and systems suitable for industrial processes and gasifiers that are designed for Integrated Gasification Combined Cycle (IGCC) power generation applications. These differences have significant implications for total system efficiencies and for readiness to separate carbon from other constituents in the synthesis gas stream.

Industrial-based gasification systems, such as Eastman Chemical Company's facility in Kingsport, Tennessee, are inherently designed to capture carbon and are more thermally efficient than stand-alone coal-fueled IGCC power generation facilities. This is also true of existing, or planned, industrial polygeneration gasification facilities that co-produce chemicals, fuels or fertilizers, in addition to electric power, or some other baseload product.

Unique characteristics of industrial gasification processes that enable or advantage high levels of carbon capture include:

- *Shift Reaction*—Most industrial gasification products (chemicals, fertilizers, transportation fuels, or hydrogen) require the syngas (the initial gaseous product from the gasifier, composed primarily of carbon monoxide and hydrogen) to be "shifted," or enriched in hydrogen. To "shift" the syngas, water is reacted with carbon monoxide in the syngas to create additional hydrogen and carbon dioxide. This "shift" step is not utilized in the non-capture IGCC systems.
- *Quench Gasifier*—The water "shift" reaction is accomplished with a "quench-type" gasifier. Hot syngas from the gasifier is quenched in water, saturating the syngas with water for the subsequent "shift" reaction. For reasons that are explained below under "Capture Required" most industrial gasification plants will be designed with gasifiers that are optimized for carbon capture.
- *High Pressure Efficiencies*—Downstream chemical conversion processes require most industrial or polygeneration gasification plants to operate at high pressures, higher than those typically required for stand-alone electric power generation. Fortunately, this same high pressure required for chemical processing also makes most carbon dioxide capture technologies operate more efficiently,

further enhancing the synergies between industrial gasification and carbon capture systems.

- *Capture Required*—In order to use "shifted" syngas for its industrial purpose(s), the carbon dioxide formed must typically be captured, and removed to low levels prior to any subsequent chemical conversion of the syngas. (To the contrary, in the IGCC case presented in the MIT study The Future of Coal, carbon capture is a parasitic cost and is undesirable absent a regulatory requirement.) Most residual carbon in the industrial-use syngas is destined for ultimate chemical conversion and is thus incorporated (or sequestered) into the final desired industrial product, rather than vented. A few examples of durable industrial products made from chemicals in which carbon is routinely sequestered include plastic handles on screwdrivers and toothbrushes, tape, and automobile paint, among many others. (Note: the carbon capture rate is normally zero for IGCC, but can be 90+% if so designed, or added later). Industrial gasification capture rates can vary widely based on products, and split of products/coproducts. Typically, industrial gasification projects would initially capture 50-90% of feedstock carbon as CO_2 or final products, but can be expanded to 90+% relatively easily compared to a stand-alone IGCC.
- *Thermal Efficiency*—Industrial polygeneration has the additional advantage of inherently greater thermal efficiency than IGCC systems. Thermal efficiencies can vary widely, but would typically be ~40% for stand-alone IGCC, and ~50-75% for industrial gasification.

These differences are indicated in the two illustrations that appear in the Appendix (pp. 7–8).*

In addition to these technology distinctions, much of America's chemical industry infrastructure is located in or near geographic regions where carbon sequestration may present a win-win opportunity with enhanced oil recovery.

So, Industrial Gasification systems present opportunities with respect to carbon capture and geologic sequestration. At the risk of using an overworked phrase, Industrial Gasification represents the "low hanging fruit" as the Congress and the Administration consider a program to test and develop CCGS technologies, protocols regulations and financing issues in a commercial setting as Drs. Deutch and Moniz of MIT recommended to the Committee on March 22nd.

Industrial gasification opportunities represent the logical economic and technological path forward to achieve four policy objectives that I believe are key to America's economic and environmental health. Those are:

1. cost-effective environmental protection;
2. energy security through reliance on domestic fuel resources;
3. reduction of natural gas prices and price volatility to all consumers; and
4. global competitiveness and millions of high technology jobs in America's industrial sector.

CHALLENGES

As promising as Industrial Gasification is for the policy objectives noted above, deployment of commercial gasification plants will not occur and the "proving ground" for CCGS will not be available unless federal and state governments provide the necessary incentives and framework to attract "first adopter" projects.

Contrary to arguments made in the MIT study The Future of Coal, gasification technology is not "commercial" today. We at Eastman have the country's most experienced and successful practitioners of industrial gasification. But our experience of more than 20 years at Kingsport is, by itself, inadequate to persuade A&E firms and financiers to reduce the risk premiums they are currently charging for first-of-a-kind gasification projects in the U.S. This premium is currently about twenty percent higher than the cost of such plants is expected to be after the first dozen or so are successfully deployed and operated in commercial service.

Incentives, such as Section 48A and 48B tax credits, are necessary to encourage commercialization of gasification projects. The use of gasification will cause the substitution of coal, petcoke and other materials for natural gas, thus resulting in decreases in demand (and presumably prices) for natural gas. The benefits to all Americans from lower and stable natural gas prices will pay for the expense of the Section 48A & B tax credit programs in short order. The other benefits previously noted make these tax programs even more compelling. However, none of these benefits accrue directly to the first adopters of gasification technology. In fact, first adopters of industrial gasification technology, operating in a globally competitive

* The appendix has been retained in committee files.

market, would be taking on more cost and risk than their competitors absent the Section 48B incentives. Financiers will be more likely to lend money to such ventures if there are external incentives to "buy down" the risk and cost for a novel project.

As the MIT study correctly points out, in Eastman's view, the same incentives should apply to carbon capture and geologic sequestration. With the exception of conventional EOR projects, where sequestration may or may not occur, there is no practical reason why a company would spend hundreds of millions of dollars to separate, transport and store carbon underground. However, doing so now could have significant informative benefits for the entire nation if carbon management is a policy objective in the future.

Federal incentives necessary to stimulate experience in carbon capture and long-term geologic sequestration and the subsequent development of protocols will be expensive. Twelve projects, based on different technologies and geologic circumstances will likely cost up to $10 billion just for the carbon capture, transportation and storage aspects of the projects. Incentives for gasification technology deployment would be a few billion additional dollars. However, the cost of imposing greenhouse gas reduction regulations in the future without a program of technology development and commercial scale deployment would certainly lead to inefficient choices, much greater expense to the country and serious loss of productivity for our economy.

Thank you for the opportunity to share Eastman's views on the opportunities and challenges associated with Industrial Gasification.

The CHAIRMAN. Thank you very much.

Dr. Ratafia-Brown, you go right ahead.

STATEMENT OF JAY RATAFIA-BROWN, SENIOR ENGINEER AND SUPERVISOR, SAIC—ENERGY SOLUTIONS GROUP, McLEAN, VA

Mr. RATAFIA-BROWN. Good morning, Mr. Chairman, Senator Domenici, and members of the committee. Thanks so much for the opportunity to appear this morning to discuss the technical feasibility of co-converting coal and biomass to clean transportation fuels via gasification technology. My testimony is based on over 30 years of broad experience conducting technical and environmental analysis of energy conversion methods, including recent project work that specifically focuses on combining biomass with coal in a so-called coal-biomass-to-liquids, or CBTL, facility.

Co-gasification of combined coal and biomass feedstock is being advocated as a potential means of producing substantial quantities of clean diesel fuel while yielding very low levels of pollutant discharges, including carbon dioxide. To both rapidly and cost-effectively achieve these goals, this concept needs to utilize the technological strengths of large-scale coal gasification technology, which enables co-conversion to produce a clean syngas at the high-pressure and-temperature conditions required for further processing into fuels and capturing carbon dioxide for sequestration.

Since the addition of biomass into a coal-based conversion system introduces unique technical challenges, the goal of my testimony is to convey that there is great promise for the successful engineering of such a hybrid energy conversion system.

Key roadblocks to future coal and biomass conversion are associated with the environmental consequences of increasing coal consumption, the relatively small scale and high specific cost of available biomass-only conversion systems, availability and handling of sufficient biomass feedstock for an economic biomass-only plant size, and shutoff risk or curtailment of operations if there is a biomass supply shortage or supply reduction.

A very promising approach to the resolution of many of these roadblocks is to combine conversion of coal and biomass within a single large facility that incorporates gasification technology to convert solid feedstock to syngas, syngas processing to remove contaminants, Fischer-Tropsch synthesis technology to convert syngas to clean fuel, and carbon capture and storage technologies for efficient and safe sequestration of CO_2. Individual plants would have to be very large to capture required economies of scale: for the transportation sector, 25,000 to 50,000 barrels per day; in the chemical sector, 5,000 barrels-per-day equivalent.

The gasifier represents the most critical component that impacts system design and operation. Fortunately, joint industry and DOE R&D efforts over the past 25 years have developed large-scale entrained flow gasification, which demonstrates the design and operational characteristics needed to effectively co-gasify coal with a variety of biomass types. Recent commercial-scale tests have validated the efficacy of co-gasification in such gasifiers located at the 250-megawatt Polk power plant in Florida and a similar one operating in the Netherlands. They were able to successfully process up to 30 percent biomass by weight, or 17 percent on an energy input basis.

My work is primarily focused on crop-based biomass, particularly switchgrass and short-rotation woody crops, such as poplar and eucalyptus. Unfortunately, their overall energy density—energy content per unit volume—is only about 10 percent that of coal. As a consequence, biomass requirements with regard to transport, storage, and handling are very high in comparison to heat contribution to the plant. Therefore, densification is required to mitigate such handling issues. In this regard, a number of relatively small-scale methods have been developed that are applicable. Pelletization, torrefaction, and pyrolysis are methods that can increase energy density from 5 to 20 times, but we really need larger-scale capabilities than currently available.

The CBTL concept also requires strict limits on various contaminants in the syngas, most of which come from coal, but biomass co-contributes elements such as calcium, phosphorous, chlorine, sodium, and potassium. Parts-per-billion limits are intended to prevent poisoning of catalysts and fouling and corrosion of heat exchangers and gas turbine blades. Fortunately, we have gained much experience with commercial IGCC power plants, and refinery and chemical gasifiers, and have established that syngas limits can be met with conservative system design.

Finally, while operation of a CBTL facility can reduce CO_2 emissions relative to more conventional coal-to-liquids design, integration of capture/sequestration technology will reduce the GHG footprint to a much greater extent. Fortunately, high pressure entrained flow gasification lends itself well to integrated CO_2 capture, yet the actual sequestration of CO_2 is not yet commercially available, and it is vital to validate it for use with the CBTL technology.

In summary, this country has spent much time and money developing the kind of gasification and related technologies that can effectively be used for coal and biomass co-conversion. Although added R&D and longer-term tests are needed to better understand how to optimize CBTL, I strongly believe that it has great potential to improve our energy security while also being a good steward of the environment.

I thank you for your kind attention.

[The prepared statement of Dr. Ratafia-Brown follows:]

PREPARED STATEMENT OF JAY RATAFIA-BROWN, SENIOR ENGINEER AND SUPERVISOR, SCIENCE APPLICATIONS INTERNATIONAL CORPORATION, MCLEAN, VA

Good Morning Mr. Chairman, Senator Domenici and Members of the Committee. Thank you for the opportunity to appear this morning to discuss the technical feasibility of co-converting coal and biomass to gaseous and liquid fuels via gasification and Fischer-Tropsch synthesis technologies. My testimony is based on over 30 years of broad experience conducting technical and environmental assessment and systems analysis for large-scale energy conversion methods, including recent project work.

Co-gasification of combined 'coal + biomass' feedstock is being advocated by researchers as a potential means of producing significant quantities of transportation fuels while yielding very low levels of pollutant discharges, as well reduced or near-zero release of carbon dioxide (CO_2), a greenhouse gas (GHG) forcing agent. To achieve these goals both rapidly and cost-effectively, this concept likely needs to utilize the technological strengths of large-scale, commercial coal gasification technology, which enables co-conversion of renewable crop-based biomass feedstock with coal, generation of suitably "clean" syngas at required pressure/temperature conditions, and the capability to efficiently capture carbon dioxide (CO_2) for sequestration. Since the addition of biomass into a coal-based conversion system introduces unique technical requirements and challenges, my goal in this testimony is to discuss the potential for successfully engineering of such a hybrid energy conversion system.

DRIVERS FOR 'BIOMASS + COAL' CO-CONVERSION

The primary motivation for converting our substantial domestic coal and biomass resources to transportation fuels and chemicals is to displace the use of imported oil and, thereby, help mitigate its high price and supply security concerns. Inclusion of biomass in this endeavor also represents a potential means of reducing the environmental footprint of this transformation on a sustainable basis. In this regard, ambitious national and international goals, like the U.S. Biomass Research and Development Act of 2000 and the Biofuel Directive of the European Union, call for large biomass-based energy conversion capacity in order to diversify the resource base for transportation fuels, chemicals, and power/heat generation. The U.S. Vision recommends that biomass supply 5% of the nation's power, 20% of its transportation fuels, and 25% of its chemicals by 2030. The EU Vision (as of March 2007) sets a goal of 10% biofuels use for transportation by 2020.

Key roadblocks to this resource conversion are associated with: 1) environmental consequences of greatly increasing coal consumption, particularly related to amplified release of greenhouse gas emissions (GHG); 2) small-scale, high specific-cost and relatively poor performance of available biomass conversion technologies; 3) availability of sufficient biomass feedstock (locally) for an economic plant size; and 4) shut-off risk or curtailment of operations if there is a biomass supply shortage or reduction in supply.

A very promising approach to resolution of most of these roadblocks is to combine conversion of coal and biomass in a large-scale facility that incorporates gasification technology to convert solid feedstock to syngas (primarily H_2, CO, CO_2, H_2O, and CH_4); syngas processing to remove unwanted contaminants such as sulfur, potassium, and mercury; Fischer-Tropsch (F-T) synthesis technology to convert syngas to clean liquid fuels (naphtha and diesel); carbon capture and storage (CCS) technologies technology to allow efficient and safe sequestration of CO_2; and power generation technology to both supply internal requirements and electricity for sale. Individual plants would have to be very large to capture required economies-of-scale: Transportation Sector—25,000 to 50,000 barrels/day; and Chemical Sector—5,000 barrels/day equivalent. I will refer to this as the coal/biomass-to-liquids (CBTL) concept.

The environmental consequences of this approach, particularly as related to the net release of CO_2, have been investigated by researchers from the Princeton Environmental Institute.[1] Their findings indicate that a plant that combines co-gasification of biomass (switchgrass) and coal could potentially achieve a near-zero net CO_2 emission rate by exploiting the negative emissions of storing photosynthetic

[1] Williams, R., "Synthetic Liquid Fuels From Coal + Biomass with Near-Zero GHG Emissions," Princeton Environmental Institute, Princeton University, January 12, 2005.

CO_2 in roots and soils. By comparison, the CO_2 emission rate for coal-only F-T liquids production, with CCS, could be reduced to about the same rate as crude oil-derived fuels. This approach could also require considerably less net biomass input to realize near-zero emissions than conventional biofuels conversion, such as cellulosic ethanol.

Let me summarize the key drivers for CBTL concept as I see them: 1) Reduction of imported crude oil; 2) Continued use of our abundant coal resources in an environmentally acceptable manner; 3) Greater utilization of our abundant biomass resources in accordance with our national goals; 4) Efficient and cost-effective utilization of biomass resources; 5) Coal acts as a "flywheel" to keep a facility operating even if biomass is not sufficiently available; 6) Within a strict carbon-constrained framework, such as McCain-Lieberman, this approach should become cost-effective, 7) Use of reliable coal in concert with more environmentally acceptable renewable feedstock may reduce project financial risk for large-scale energy conversion plants; and 8) Gasification-based projects could benefit significantly from the more positive public attitude displayed towards co-utilization of renewable feedstock, as well as development of a reliable multi-source fuel supply network for such projects.

Successful technical and cost-effective implementation of CBTL particularly depends on adoption of suitable gasification technology, addressing biomass handling challenges, satisfying syngas "cleanup" constraints, and effectively integrating CCS. My intent in the remainder of this testimony is to focus on the challenges that each represent and their potential for enabling this concept to function effectively.

GASIFICATION TECHNOLOGY CAPABILITY AND EXPERIENCE

First, I want to convey that gasification technology is in widespread use today. The 2004 World Gasification Survey, sponsored by DOE, shows that in 2004 existing world gasification capacity had grown to 45,000 MWth of syngas output at 117 operating plants with a total of 385 gasifiers. Coal (49% of capacity), petroleum products (37%) and natural gas (9%) currently dominate the gasification market as the primary feedstocks for production of F-T liquids, chemicals, and power. Note, however, that biomass gasification only accounts for about 2% of the total syngas production. Exhibit 1* presents a summary of large-scale gasification experience.

The gasification technology represents the most critical component that impacts system design and operation of a CBTL facility. The desirable design characteristics for co-gasification technology for F-T liquids applications (using high rank coals) are: large individual gasifier throughput (>1000 MWth); high temperature (>2,300 °F to eliminate tars/oil contaminants in the syngas); high pressure to increase syngas throughput and reduce process component sizes; oxygen-blown (as opposed to air-blown) to eliminate nitrogen as a syngas diluent; slagging (a consequence of high temperature operation) to render most of the feedstock ash as a benign byproduct for utilization purposes; dry feed of biomass since it is difficult to handle as a slurry, and use of a relatively large particle size to reduce feedstock preparation.

Fortunately, these design characteristics are generally met with the widely used entrained-flow gasification technology, which currently dominates the large-scale gasification market with 85% of the installed units. (Note that this technology also continues to benefit from a variety of related R&D efforts sponsored by DOE to further improve performance and cost, including development of a compact transport-type gasifier technology.) While these gasifiers are quite flexible with regard to feedstock characteristics, their high reaction rates demand very small feedstock input size (e.g., <100 micron or 0.004 inches) that is easily achievable for friable materials like coal, but more challenging and energy-consuming for biomass feedstock. Compounding this important issue is the high pressure injection requirement for the entrained-flow technology, which may present a challenge to biomass injection into the gasifier. Also, the chemical make-up of biomass ash will cause it to behave differently that coal ash, which must be accounted for in design and operation. Several large-scale demonstrations of entrained-flow co-gasification of coal and biomass have already been performed here and in Europe.

Commercial scale co-gasification of biomass with coal has been demonstrated at the 253 MWe Nuon IGCC power plant in Buggenum, The Netherlands (using the dry-feed Shell entrained-flow technology), as well as at Tampa Electric's 250 MWe Polk IGCC power plant (using GE entrained-flow technology). (The latter was built in the 1990s as part DOE's Clean Coal Demonstration Program.) The Nuon plant recently tested biomass content up to 30% by weight (17% of total energy input), which requires up to 205,000 tons/year of biomass feedstock and coal feed is about 435,000 tons/year. Besides gasification of demolition wood, tests were also conducted

* All exhibits have been retained in committee files.

with chicken litter and sewage sludge. The co-gasification tests conducted at the Polk plant used up to 1.5% by weight of woody biomass harvested from a 5-year-old, locally-grown Eucalyptus grove. Since the plant uses 2,200 tons/day of coal, the biomass co-gasification basis was 33 tons/day (about 10,000 tons/yr).

Not only did these plants operate normally, but we can generally conclude that biomass feed size can be on the order of 1 mm (0.04 inches) due to biomass' high reactivity relative to coal. The importance of this lies in the capability to minimize biomass milling power consumption and possibly avoid other efficiency-reducing pre-treatment processes. The Nuon experience has also shown that a relatively high throughput of biomass is possible in an entrained-flow unit that is co-gasifying coal. Pilot-scale tests were also tests were also conducted at the National Energy Technology Laboratory (NETL)/Morgantown some years ago with coal and up to 35% biomass.

COAL + BIOMAS CO-GASIFICATION CHALLENGES

Below, I provide a brief overview on key challenges associated with oxygen-blown, entrained-flow gasification of coal and biomass.

Oxygen feed to the gasifier—standard cryogenic method of oxygen production is both costly and energy intensive; however, DOE is well into development of so-called ion transport membrane (ITM) technology, which promises significant cost reductions and efficiency gains.

Biomass and coal injection—Feedstock injection into high pressure gasifiers is challenging. Conventional dry-feed methods employ a series of complex lock hoppers. Due to the low energy density of biomass, lock hoppers have two major disadvantages: (1) large amounts of inert gas are required and must be compressed, and (2) gasification efficiencies drop due to the dilution of the syngas. Fortunately, DOE's gasification program has been developing a rotary dry-feed coal pump that, when fully tested, should allow the feedstock to be "pushed" directly into the gasifier.

Biomass particle size—While entrained-flow gasifiers require very small coal particle sizes (<0.004 inches), recent commercial 'coal + biomass' tests suggest a much larger size (0.04 inches) is likely feasible due to the high reactivity of biomass due to its high O_2 and volatiles content

Biomass ash slagging behavior—While the slagging performance of the biomass ash may be an issue, testing has shown that "flux" material (aluminum-silicates) can be added to the gasifier to re-establish acceptable ash slagging performance.

The bottom-line is that the practical limit of biomass co-processing with high rank coals (bituminous and subbituminous coals) is probably associated more with biomass preparation and feed issues and desired syngas production level, than the capabilities of the entrained-flow gasification process.

BIOMASS HANDLING CHALLENGES

Our work has primarily focused on crop-based biomass, particularly prairie grass/switchgrass and short rotation woody crops (SRWC), such as Poplar and Eucalyptus. These are defined as fast-growing, genetically improved trees and grasses grown under sustainable conditions for harvest at 1 to 10 years of age. In general, their biomass heating values [MJ/kg] and particle densities are about half of that of coal, whereas bulk raw densities [kg/m^3] are about 20% of that of coal, resulting in overall biomass energy density [MJ/m^3] approximately 10% of coal (see Exhibit 2). As a consequence, when co-gasifying raw biomass at a 10% heat input rate with coal, the volume of coal and biomass can actually be similar; therefore, biomass requirements with regard to transport, storage and handling are very high in comparison to its heat contribution.

Biomass either has to be located very close to a conversion facility and processed immediately, or some form of "densification" needs to be implemented to mitigate handling issues. Since this is a well-recognized issue for biomass, especially for conversion processes that can consume very large quantities, a number of methods have been developed, albeit currently at small-scale, that are applicable. These are pelletization, which is a drying/compression method that increases energy density of switchgrass pellets by a factor of eight. Torrefaction is a "roasting" treatment that operates within a temperature range of 200 to 300 °C and is carried out under atmospheric conditions in the absence of oxygen. This process not only increases the energy density of wood by about 25%, but also greatly reduces the milling energy consumption to reduce size. Combined torrefaction and pelletization can increase the energy density of wood by about five times. Pyrolysis is an option to produce a liquid product (pyrolysis oil) from biomass, via its thermal decomposition, at temperatures of 450-550 °C. Yield efficiency of pyrolysis oil production averages about 70%, and volumetric energy content of pyrolysis oil is 19 68,300 Btu/gal compared with No. 6 Oil at 144,000 Btu/gal.

SYNGAS "CLEANUP" CONSTRAINTS

The CBTL concept requires strict limits on various contaminants in the syngas, most of which come from coal, but biomass co-contributes certain elements and related compounds such as calcium (Ca), phosphorous (P), chlorine (Cl), sodium (Na) and potassium (K). The limits are intended to prevent poisoning of the F-T catalysts and fouling/corrosion of downstream system components, such as heat exchangers and gas turbine blades. As an example, constraints on alkali metals (Na + K) are less than 10 part per billion by volume (ppbv) and halides (HCL + HBr + HF) are also less than 10 ppbv. These and other limits are controlled via the integration of a group of processes that sequentially treat the syngas once it exits the gasifier. These include dry particulate removal, wet syngas scrubbing for fine particulate and gases, mercury removal, and acid gas (H_2S and CO_2) removal. Experience with commercial IGCC power plants, such as the Polk IGCC plant and the Wabash River plant (another DOE Clean Coal Technology Program investment), as well as refinery gasifiers, have established that the CBTL syngas limits can be met with appropriate system design.

CARBON CAPTURE AND STORAGE CHALLENGE

Operation of a CBTL facility will reduce CO_2 emissions relative to a more conventional coal-to-liquids (CTL) design, even without integration of CCS technology. The extent of the reduction depends on the relative level of biomass energy input. For example, the 30% (by weight) biomass feed to the Nuon plant that I discussed previously, resulted in an effective CO_2 reduction of about 17% or 220,000 tons/yr (excluding GHG emissions related to biomass collection and treatment). On the other hand, integration of CCS technology will reduce the GHG footprint of CBTL to a much greater extent. However, while CO_2 capture technology is commercially available and well-proven for gasification-type applications, it increases capital expenditure and operating costs; DOE is currently developing advanced membrane technologies to lower this impact. More importantly, the actual sequestration of CO_2 is far from commercially available and acceptable. As stated by DOE, key challenges are to demonstrate the ability to store CO_2 in underground geologic formations with long-term stability (permanence), to develop the ability to monitor and verify the fate of CO_2, and to gain public and regulatory acceptance. DOE's seven Regional Carbon Sequestration Partnerships are engaged in an effort to develop and validate CCS technology in different geologies across the Nation. This is vital to sequestration's future and use with the CBTL technology.

CONCLUSION

Even without considering currently favorable government programs to encourage investment in CTL and CBTL technology, I've endeavored to convey that that there are considerable drivers that strongly support continued development. Importantly, it takes advantage of the significant investment and progress that the country has made with gasification and related technologies over the past twenty-five years. Commercial entrained-flow gasification technology has been proven to be capable of co-gasifying coal and biomass, which at the minimum would permit reduced GHG emissions from future CTL facilities. Incorporation of CCS technology, when sequestration is technically available and appropriate to regulatory conditions, can have a major impact on the sustained use of our abundant coal resources and greater use of our biomass resources. Although, I've reported on some successful tests of coal and biomass co-gasification, I've also attempted to convey that R&D is needed to deal with significant challenges related to biomass handling and feeding issues that are important to plant operability and cost-effectiveness. Also, longer-term, large-scale tests of the CBTL concept are required to better understand how a well-integrated design will perform and function. Overall, I strongly believe this is a technology that has great potential to improve our energy security while also being a good steward of the environment.

I will be happy to answer any questions.

The CHAIRMAN. I thank you very much. Thank you all for your good testimony.

Let me start. And we'll do 5-minute rounds here.

I'll start with a question to Mr. Fulkerson. The idea you presented, which you attributed to Bob Williams at Princeton, was presented last month when you had your group together, your research and development group, folks from the National Laboratories, as I understand it. Could you be a little more explicit about what is the extent of the capture and sequestration that would be required as part of this? I mean, if this combined biocoal effort is adopted, or this technology is adopted, would there also have to be an attendant capture and sequestration effort made in order for it to meet the environmental standards that you think are appropriate?

Mr. FULKERSON. Yeah, of course. As Jay has just pointed out, the biomass coal gasification process has to be accompanied by sequestration of all of the CO_2 that is excess in the process. But the interesting point is that the biomass carbon which is sequestered is a net-negative, and, therefore, it offsets the carbon that is emitted subsequently by burning the product fuel, so that the overall well-to-wheel kind of climate impact can be net-zero. That's——

The CHAIRMAN. OK.

Mr. FULKERSON [continuing]. The important point of it.

The CHAIRMAN. "Net-zero," meaning that there would be no requirement for a separate carbon capture and sequestration effort as part of this. Is that what you mean by "net-zero"?

Mr. FULKERSON. Yes. What I mean is the overall process, including burning the product fuel——

The CHAIRMAN. Right.

Mr. FULKERSON [continuing]. Produces net-zero carbon emissions. In other words, most of the of the carbon is sequestered, but the carbon that is sequestered includes carbon from biomass, which is a net-negative, since biomass, in being grown, absorbs CO_2 from the air.

The CHAIRMAN. Right.

Mr. FULKERSON. So, that's got——

The CHAIRMAN. So, you're saying that, by sequestering the carbon, you then are net-positive, and then, when you burn the fuel, you use up your net-positive, and you come out——

Mr. FULKERSON. Right.

The CHAIRMAN [continuing]. At zero.

Mr. FULKERSON. Right. Right.

The CHAIRMAN. OK.

Mr. FULKERSON. I said——

The CHAIRMAN. Let me ask Dr. Herzog if you agree with that analysis, that this would be where you wind up in the process.

Ms. HERZOG. Yes, I do agree with the analysis, but let me make a slight distinction.

The biomass is good. If you just used biomass, you'd be net-negative. Including the coal, thus, brings you back up. You could get net-zero, but that means using a lot of biomass in this system. The question, I think, is, "Is that the best use of all this biomass, with the goals in mind that we have, which is to reduce our oil dependence and reduce our global warming emissions?" That's what needs to be assessed properly.

The CHAIRMAN. Mr. Fulkerson, you seemed to disagree with some of that.

Mr. FULKERSON. Dr. Herzog, let me add to what you said.

The beauty of biomass and coal together is that the amount of biomass that you have to use per unit of product fuel is much less than you would have to use if you went the cellulosic ethanol route. That's the interesting trick of this. That's the, "Why is that?" It's because the coal supplies most of the energy to run the process. That's the reason you get a much smaller requirement of biomass to come up with this zero-net carbon emissions——

The CHAIRMAN. I'm about to run out of my time here, but let me just nail down the stage this idea is in. This was presented to you last month in your R&D group. Are there examples of this functioning? Are there demonstration projects that are using this technology? Where are we? I mean, are we looking at doing this 2 years from now, 5 years from now, 10 years from now, on a commercial scale?

Mr. FULKERSON. Yes, I would say that Dr. Ratafia-Brown's testimony gave you where the state-of-the-art is. As I understand it, there's up to 10 or 15 percent biomass with coal in gasification in the Netherlands, so these things are coming along. There is no inherent reason why they shouldn't work, except the kind of details that Jay pointed out, which are a lot of details of things have to be ironed out for this. His testimony provided us closer to the state-of-the-art, as well as Jim Bartis, here.

The CHAIRMAN. OK. All right. Well, I don't want to overstay my time. Let me go ahead and call on Senator Domenici.

Senator DOMENICI. Chairman, you're welcome—if he wants more time, go ahead.

The CHAIRMAN. Well, let me just ask one question of Dr. Ratafia-Brown.

You say in here—I think he's referring to page 5 of your testimony, where you talk about this plant in Belgium—or in the Netherlands, excuse me.

Mr. RATAFIA-BROWN. That's correct.

The CHAIRMAN. Yes. Could you tell us what the status of that is? I mean, if this is such a great technology, and the Dutch have been doing this for some period of time here, I guess——

Mr. RATAFIA-BROWN. Well, the reason that came about, Senator, is because the Dutch have a mandate for this plant to reduce their CO_2 contribution to the Dutch inventory, and they placed—I believe it was a 200,000 ton-per-year reduction of CO_2 on this facility. They fought—therefore, back in 2001, to co-gasify chicken litter and wood waste and some other biomass, up to, I believe, in 2004, it was 30 percent by weight, which was about 17 percent on an energy-input basis to the plant. They've successfully done this. They've had some technical issues, but I think the overall experience is quite good. Therefore, their CO_2 reduction has come strictly from the co-gasification of biomass.

The CHAIRMAN. You're suggesting that we could do something similar in our coal plants?

Mr. RATAFIA-BROWN. We have two plants in this country that operate very similar to that. It's the Polk Plant in Florida and the Wabash River Plant in Indiana. They both operate integrated gasification combined-cycle plants. The Polk Plant also has tested biomass at their facility very successfully back in—I think it was——

The CHAIRMAN. Very successfully as a way to reduce the emission?

Mr. RATAFIA-BROWN. It was just a test to see if they could process it and reduce emissions, that's correct.

The CHAIRMAN. OK. All right, thank you.

Senator Domenici.

Mr. RATAFIA-BROWN. You're welcome.

Senator DOMENICI. Mr. Bartis, to follow your middle-of-the-road—what specific steps would the Congress have to put in place? If we take those steps, what is the likelihood of success? Please give us this list, again, now.

Mr. BARTIS. Well, the first step is to resolve the uncertainty associated with what these fuels really cost.

Senator DOMENICI. All right, so——

Mr. BARTIS. We just don't have a handle on that. It's not very expensive. We could cost-share, with private industry, the development. But there are no funds allocated to this right now. But if we could get the front-end engineering design, then we would know what these plants cost. Truly know.

Now, let me put this in perspective. These plants run billions of dollars. The detailed engineering package for a plant like this would be a couple—100 million, $200 million to get the blueprints. Before you go to that step, you go and get a front-end engineering design. That costs about $30 million. I believe that it's possible that, if the Federal Government came in with a 50–50 cost share, we could get extremely valuable information on what these plants truly cost. Right now, we're dealing with very low-level design work primarily done for R&D purposes, not for investment quality. The second step——

Senator DOMENICI. There would be no reason for you to think that this kind of investment would produce the kind of technology application and reality of——

Mr. BARTIS. Well, our view—we've spoken with a large number of firms—is that without an incentive package, you're not going to get the participation of the private sector here. So, unless it's through a broadbased tax or through specific incentives—and we've looked at these incentives—we're not going to make progress here. There's just too much uncertainty on world oil prices.

Senator DOMENICI. OK. Now, in your opinion, if you did have the incentives, is the technology apt to produce a feasible plant——

Mr. BARTIS. Yes.

Senator DOMENICI [continuing]. That will do the job?

Mr. BARTIS. Yes. We have options right now for the initial set of plants for carbon management. There's no reason that any of these plants should exceed what's typical when we use oil in refining. So, the first set of plants can certainly come out—what I'll call carbon-neutral, in the sense that they're no worse with regard to emissions than the oil that they're going to displace.

Senator DOMENICI. All right.

Mr. BARTIS. And we have those applications here and now. And in the future we've got a great chance to go to what Mr. Fulkerson described as zero emissions, as good as you can get.

Senator DOMENICI. All right. Now, let me ask—if we did this, is it possible that the best incentive might be for us to do this on a plant-by-plant basis to get it started, by saying we'll take three of them, let's say, or four, and we will say—we've got this agreement, and the price will come out all right, because the American Government will buy the stream at a price that is assured?

Mr. BARTIS. We have looked at that option, and our analysis says that a purchase commitment may not be in the best interest of the taxpayer, that there——

Senator DOMENICI. OK.

Mr. BARTIS [continuing]. Are better options in which risks can be shared better. Those options—if you'd like, I can summarize.

Senator DOMENICI. Sure.

Mr. BARTIS. The most effective option to getting the best of our firms involved is probably a front-end incentive, such as a tax credit, which improves the overall investment profile of such a plant.

Now, the second important incentive is something that protects the investor, in case oil prices plummet. The larger that front-end incentive is, the lower that barrier needs.

Finally, we believe that it's very important to look at cost-sharing. The companies we've talked with also see that as a favorable approach, some kind of collar so that there's some kind of recapture of the Federal risk-taking.

We don't at all see loan guarantees as a useful tool, because they don't attract the right set of players here.

Senator DOMENICI. OK. Let me just summarize, from my standpoint, with the two of you, Mr. Bill Fulkerson, speaking either for yourself or for your mentor, whichever you like, if that's what he is, and then—if you can speak for him—and James Bartis. Talking about this subject and wondering where we have something that will work—now, there may be more things that will work, so I'm not trying to tell our committee this is the only one. But you are suggesting there is a known technology that has had sufficient practice, albeit not with a large commercial plant, but that there has been sufficient practice with it that the two of you believe, with proper up-front incentives that are fair, that we could, indeed, get in this and come out with a plant or two, whichever we choose—and we can have a little bit more variety, but if our goal is to produce a plant that is neutral, in terms of carbon emission, we could do that, if we want, and get it built, to show the world that carbon can be used for this purpose. Is that right, Mr. Fulkerson and Mr. Bartis? Is that what you're telling this Senate committee?

Mr. FULKERSON. Well, I think what you said if you mean carbon-neutral as good as petroleum——

Senator DOMENICI. As——

Mr. FULKERSON [continuing]. Then, absolutely, yes. Absolutely yes.

Senator DOMENICI. All right. Let's say it that way for the record.

Mr. FULKERSON. Okay. If that's what your goal is—if your goal, however, is to be better than petroleum, because petroleum is a major emitter of carbon dioxide in the world—then you have to incentivize, as well, other technologies, such as the biomass/coal combination. Now, it's not going all that much further to do that. So, I think that with existing technologies, or near existing technologies, that you could accomplish both, and you should. In my testimony, I gave about six policies that, in concert, I think, would drive us in the right direction without specify—with picking winners, without picking technological winners. In other words they're technology-neutral. This is one of the technologies that would be incentivized. Whether it's the one that would win, I don't know, but—anyway.

Senator DOMENICI. Mr. Bartis.

Mr. BARTIS. I endorse that. We have the technology on the shelf today, and we can make it better than it's ever operated in the past by putting the right companies in charge. But it's on the shelf, and we can build it today. We can match the carbon emissions of conventional petroleum. That's the good news. We can solve a major national security and economic problem.

The other critical component is going beyond that and, over the longer term, building these plants, and to get that done means we have to demonstrate, at multiple sites, carbon capture and sequestration. That is not in the current plans of the Department of Energy. It's critical. In fact, I believe that maybe two or three of these initial plants, could be used to generate the carbon dioxide needed for those massive demonstrations. But it's critical that we move forward there.

Mr. FULKERSON. Jim, let me ask you—you said that we could do the existing thing today, without sequestration. That—and be equivalent to petroleum—that's not true. Your gasification liquids process will produce about twice as much of CO_2 as petroleum. So, to even bring it neutral, you have to sequester the excess carbon. Isn't that right?

Mr. BARTIS. I was thinking of initial plants using it for enhanced oil recovery operations, or as a demonstration of these carbon sequestration.

The CHAIRMAN. So, that's another way of sequestering it.

Mr. BARTIS. Another way of sequestering would be enhanced oil recovery.

The CHAIRMAN. Right.

Senator Bunning.

Senator BUNNING. My goodness, where do I start?

Since I have a bill in, I've got to get to the coal-to-liquids use with biomass to produce a fuel, whether it be a fuel that is used in trucks and/or diesel fuel. But, even more importantly, I've been dealing with the Air Force, and they are so interested in this process as a national security issue, where we use the same type of process, including biomass, to produce aviation fuel.

Mr. Fulkerson, is that a distinct possibility, to produce the same type of diesel and aviation fuel by using biomass and coal?

Mr. FULKERSON. Absolutely.

Senator BUNNING. And, therefore, reducing the footprint.

Mr. FULKERSON. The only difference is the——

Senator BUNNING. It's the cost of building the plant.

Mr. FULKERSON. Yes.

Senator BUNNING. OK. If we incentivize that and change the rules—we've got bad rules, as far as purchases by the Air Force, so we limit it to a 5-year contract, and you have to pay as you go each year—we've got to change the rules if we're going to allow the Air Force to use that fuel. So, I want to get this correctly through my head, because of all the misinformation that's out there.

The technology now exists to produce, with coal and biomass, a fuel that will burn as clean as our petroleum-based fuels, presently. If we use the carbon capture at the plant, and use it for other purposes, or sell it, or we sequester it, we have a much better fuel than a petroleum-based fuel. Anybody?

Mr. FULKERSON. Absolutely. Absolutely.

Senator BUNNING. Mr. Brown? Since you're in the business, and—David, you are also in the business, and you are in the business, Jim—go ahead.

Mr. BARTIS. Allow me to make one caveat here.

Senator BUNNING. OK.

Mr. BARTIS. All right. The use of biomass and coal is an extremely low-risk option. However, as Mr. Ratafia-Brown has mentioned, although there has been experience, it's been very limited experience——

Senator BUNNING. Correct. It's not——

Mr. BARTIS [continuing]. Versus.

Senator BUNNING [continuing]. Large-scale.

Mr. BARTIS. So, there may be——

Mr. RATAFIA-BROWN. It had been large-scale.

Mr. BARTIS. It has been large-scale, but on only specific types of biomass——

Senator BUNNING. OK.

Mr. BARTIS [continuing]. I think we all agree there may be a need to do some large-scale testing before a company would be willing to put this technology on a multibillion-dollar plant. There may need to be some tests. I know there are test sites available, and this could be done——

Senator BUNNING. My time's running out. What I want to ask is that—similar to Senator Domenici—we know we have a big picture out here. If we don't put coal-to-liquids technology in the picture, we are limiting our options to synthetic fuels, whether it be just ethanol, or whether it be soybeans to diesel, or whatever—we're limiting our options. Therefore, we're still going to be dependent on Middle East oil or oil from somewhere. So, why not look at all the options and incentivize all the options so that we can get all of the things on the table at once?

Would you agree or disagree? Go ahead, ma'am. Please.

Ms. HERZOG. Thank you. I'd like to take a step back and, again, look at what the goals are. The goals are to reduce oil, and also, from our perspective, reduce global warming emissions, and not to pick the winning technology——

Senator BUNNING. I don't want to pick them.

Ms. HERZOG [continuing]. Which is what you're saying. And I——

Senator BUNNING. No, but I said put them all out.

Ms. HERZOG. So, the way—we believe—to do that most effectively is to set the standard and let the market find the most promising technologies. Very possibly, it might be what you're suggesting, but that needs to play on an equal playing field with all the other opportunities out there.

Senator BUNNING. I agree. But we also have to get some kind of global agreement. The United States can get to zero in emissions. If we don't get an agreement out of China and India and other places to lower their emissions, we are not going to have an effect on global warming anywhere in the world because China's going to open up 94 coal-fired generation plants this year, with no restrictions on them.

Ms. HERZOG. But——

Senator BUNNING. So, we need to have some kind of an agreement, globally.

Ms. HERZOG. I absolutely agree, and we're as concerned about China and the rest of the world as you are, and also concerned about U.S. emissions.

Senator BUNNING. Thank you very much, panel.

The CHAIRMAN. Senator Salazar.

Senator SALAZAR. Thank you very much, Chairman Bingaman and Senator Domenici, for holding this very, very important hearing.

I appreciate your knowing that many of us on this committee come from States that have a lot of coal, and use a lot of coal in powering the energy that we use. In my State, 71 percent of our electricity is generated from coal. We have coal mines and coal miners throughout the western slope of my State through the southern end of my State, and I recognize coal has this abundance that makes it a very attractive place for us to look at addressing the national security and environmental security issues of our time.

So, the real debate, it seems to me, here in this committee, and probably on the Senate floor, will be how is it that we can move forward and develop the use of our abundant coal resources in a way that does not do damage to our environment, in a way that does not compromise our environmental security?

So, I have a couple of questions. First, to you, Dr. Herzog. In terms of a hybrid electricity technology for vehicles, is there a way, through IGCC, and through moving forward with advanced vehicle technologies, with battery-powered vehicles that are plugged in at night—is that the kind of thing that you think has some possibility for us to use some of our abundant coal resources?

Ms. HERZOG. Absolutely. GM is developing plug-in hybrid electric vehicles. So are other automobile companies. The exiting thing about plug-in hybrid electric vehicles, which I said in my testimony and remarks, is that you can use coal gasification, capture the carbon dioxide, create electricity to the plug-in hybrid electric vehicle, save much more oil, and reduce greenhouse gas——

Senator SALAZAR. Let me ask you, then, this. What is it that we, as a committee that understands the volume of coal that we have available here in the United States of America, can do to further incentivize that goal——

Ms. HERZOG. Right.

Senator SALAZAR [continuing]. To happen sooner than later?

Ms. HERZOG. Right. So, as I said just now, I don't believe in picking technologies. I think this could very possibly be the winner, but what we need to do is put a cap on our carbon emissions, headed to where we need to be in the next decades to come, so a declining cap that will set a market signal on carbon. In addition, I think standards to help promote—an incentive to help promote technologies, more general within a carbon cap, make a lot of sense. For example, a low-carbon fuel standard, where electricity to plug-in hybrids would qualify. To have that low-carbon fuel standard starting at a level, in a few years, and then slowly ramping down over time to make sure that our transportation sector emissions are heading in the direction they need to be heading, and not to invest in technologies today which won't make any sense in 10–20 years.

Senator SALAZAR. Thank you, Ms. Herzog.

Mr. Fulkerson, I think it was you that testified about the fact that we already have two IGCC plants that use biomass here in our country, one in Polk, Florida, and one in Wabash, Kentucky. Was that your testimony, or another witness?

Mr. FULKERSON. Jay's testimony.

Senator SALAZAR. That was Jay's testimony. Let me ask you both. Given two plants that have already been doing IGCC with biomass that deals with the greenhouse emissions issue, why isn't this technology being, essentially, deployed, and being picked up by the commercial market, at this point in time?

Mr. RATAFIA-BROWN. Well——

Senator SALAZAR. Jay and Bill, why don't you take a quick——

Mr. RATAFIA-BROWN. Well, we don't currently operate within a climate change framework. There's no incentive for these plants to use a crop, that they may have to pay for, to add to their, you know, already plentiful fuel supplies. Now, in the State—in the case of the Netherlands, their country did mandate that that plant——

Senator SALAZAR. So, for the case of the Florida and Kentucky plants, they just did it out of being——

Mr. RATAFIA-BROWN. That was a test——

Senator SALAZAR [continuing]. Good Samaritans. They just wanted to go and try it——

Mr. RATAFIA-BROWN. It was——

Senator SALAZAR [continuing]. To see how it worked.

Mr. RATAFIA-BROWN [continuing]. A test to determine whether that gasifier can handle it, and——

Senator SALAZAR. The results of those tests, you said, were positive?

Mr. RATAFIA-BROWN. Extremely positive.

Senator SALAZAR. OK. But it was just a test. They're not currently using it.

Mr. RATAFIA-BROWN. That's correct. I do——

Senator SALAZAR. OK.

Mr. RATAFIA-BROWN. [continuing]. Want to point out one thing, if I might, with regard to these plants, these CBTL plants. They not only produce fuels, they do produce electricity for plug-in hybrids. A 50,000 barrel-per-day plant will also produce 125 megawatts of electricity for sale to the grid. So, these——

Senator SALAZAR. Dr. Herzog, what's——

Mr. RATAFIA-BROWN. [continuing]. This is a win-win-win.

Senator SALAZAR [continuing]. What's the problem with moving forward with projects like the ones that have already demonstrated what they can do in Kentucky and Florida?

Ms. HERZOG. Well, my understanding is, the Polk Plant is a coal gasification plant that produces electricity. It's been running for quite some time. If they added biomass, it was only—I mean, it's not running on biomass now.

Mr. RATAFIA-BROWN. No, no. That was strictly a test sponsored by the Department of Energy—again, to test the viability of it.

Senator SALAZAR. Well, the tests work. Here's my question I'm trying to get to. We know the tests work in the Netherlands, we know they worked in Florida, we know it worked in Kentucky. The question is, "How do we make that happen on more than a test basis, whether it's these two plants or 50 plants, or whatever the number is?"

Mr. RATAFIA-BROWN. Well, I think that——

Senator SALAZAR. Dr. Fulkerson——

Mr. RATAFIA-BROWN [continuing]. Speaks to what Jim was talking about.

Senator SALAZAR. Dr. Fulkerson, why don't you respond?

Mr. FULKERSON. You've got to make the economics work. The problem is that unless there is a carbon tax, or equivalent, then there's not adequate incentive to build a plant that sequesters carbon, for example. OK? Without that, you're not going to have anything happening in the private sector until you put that regulation in place, which I assume——

Senator SALAZAR. The carbon limitations—

Mr. FULKERSON [continuing]. That the Congress——

Senator SALAZAR [continuing]. You think, will drive the economics to be able to make this more than a test kind of project in Florida and Kentucky.

Mr. FULKERSON. That——

Senator SALAZAR. Let me—I've gone over my time by a minute, and I respect the chairman so much for letting me do that.

Mr. FULKERSON. That's what you need.

Senator SALAZAR. So, I yield back, Mr. Chairman.

The CHAIRMAN. Thank you very much.

Senator Corker.

Senator CORKER. Yes, sir. Again, Mr. Chairman, this has been an outstanding panel, and thank you for your leadership in putting it together, along with our ranking member.

I know that one of the components of our biofuels bill limits the amount of corn to ethanol that's utilized, because there's concern, I guess, about the food industry and what's happening there. Yet, what I'm hearing from this panel today is that by using coal and biomass, we're actually able to take those same feedstocks, if you will, and cause them to go far further, putting less pressure on our food industry. Is that what I'm hearing? Does everybody agree with that?

Mr. FULKERSON. That's what Bob Williams has shown. It's a very important—very important point. Very important point.

Senator CORKER. OK.

I want to share the enthusiasm to plug-ins, by the way, Dr. Herzog. Let me just—you mentioned, in your written testimony, how, basically, coal-to-liquid technology uses a tremendous amount of water. I just wondered how that compared to the production of corn ethanol or cellulosic ethanol. How does it compare?

Ms. HERZOG. It's a good question. I'm actually not an expert on the biofuels process, so I'll have to get back to you on the answer to that.

Senator CORKER. Would it be reasonable to assume, though, that a large amount of water is used in both?

Ms. HERZOG. I simply don't know, for the biofuels process.

Senator CORKER. Well, it would be interesting for you to get back to us, or——

Ms. HERZOG. Yes.

Senator CORKER [continuing]. Someone else, because that was listed as a strong negative to this, and nobody knows.

Mr. BARTIS. The water—this is the water used in coal-to-liquids. I can——

Senator CORKER. That's——

Mr. BARTIS. All coal and biomass to liquids, I can——

Senator CORKER. Yes.

Mr. BARTIS [continuing]. Report on that.

The water use is highly dependent on how you design, and where you design, your plant. If you design a plant where water is not abundant, you will put in certain features in that plant—for example, dry-cooling towers—that cost more, but that allow you to use much, much less water. So, our estimates of water use is, it's widely ranging, depending on where you build the plant. It can be as low as a barrel and a half of water per barrel of product to as high as seven barrels of water per barrel of product, depending on what water costs and its availability.

Senator CORKER. OK. As I'm listening to the development of this technology, I know that in our own biofuels bill we're depending, in a big way, on cellulosic use. I mean, it's a technology that is not at commercial use today. Yet, we're depending upon that to reach these levels that we talked about. Where would you say we are in the development of coal-to-liquid technology as it relates to cellulosic technologies? It sounds to me that we may even be further down the road with this technology than we are commercially, using cellulosic.

Mr. BARTIS. Can I comment on that?

Senator CORKER. Yes.

Mr. BARTIS. We have looked at both.

Senator CORKER. OK.

Mr. BARTIS. Right now, I can say that there is not a doubt—there should be no doubt—that one can take biomass and put it into a gasifier and make liquids. That is a very, very low-risk option. We have looked, also, at the concept of taking cellulosic materials and making alcohols. Right now, we see no evidence that that option is a very high-risk option. There's a lot of money being invested in that option by the Government. It's a very high-risk option. We see no evidence that that option is going to be less expensive than the Fischer-Tropsch gasification option for straight biomass. When we add coal, there's a good chance it may be even less expensive. So, at this time, we can't say that—we have a near-term option, and we don't see the long-term option being much less.

Senator CORKER. Before you answer, Mr. Fulkerson, let me just generally ask this question, and you can answer this. I'm going to run out of time. It seems to me that the way we have now drafted this bill, we are picking winners and losers. It seems to me that we might be better serving our country by just setting standards, as Dr. Herzog has laid out, and many of you, and letting the market decide. It seems to me that we are listening to a very viable avenue today. Certainly, I think, plug-ins is going to be a very, very viable option down the road. It seems to me that we may be remiss in actually defining gallonage by certain sources, versus just setting a standard and letting that gallonage be in the mandate. Would you all agree or disagree with that?

Mr. FULKERSON. I would certainly agree. I would certainly agree. In fact, in my testimony, these six policies I talk about are designed not to be technology-specific. The one advantage of cellulosic ethanol is that it doesn't require sequestration. It produces liquids that are carbon-free, effectively, without sequestration. All the coal and biomass gasification processes, in order to work as being neutral to the climate, require sequestration. So, I wouldn't give up on either one.

Senator CORKER. But we could set carbon standards——

Mr. FULKERSON. And that would——

Senator CORKER [continuing]. With this, and we could solve——

Mr. FULKERSON. Just then let the winner take all.

Ms. HERZOG. I obviously agree. Just one quick point. On the biomass co-firing gasification and coal-to-liquids process, we have one project in the Netherlands, maybe some demo runs have been done in the United States—it's far from clear to me that this is viable technology ready to jump out into the marketplace at this point in time.

The CHAIRMAN. Let me just ask a question. I know Senator Craig is next, and then Senator Murkowski. But just following up on Senator Corker's point there. In the bill that we reported out of our committee, we provided—any new plants that were constructed to provide ethanol from corn, from traditional feedstocks, would have to be able to demonstrate—that the life cycle emissions of greenhouse gases were 20 percent less than in the case of gasoline. It was urged on us, although we didn't put it in the bill, and we may consider it again on the floor, that any ethanol produced from advanced biofuels, which was essentially cellulose-based ethanol, would be at least 50 percent less in emissions—life cycle emissions than traditional gasoline. Are those the standards that you're talking about, that if those were in the bill, and applied to any gas— or any gasoline-equivalent-type fuel, you think that would be an appropriate way to go?

Ms. HERZOG. Yes, we think that's an appropriate standard. Then super-advanced would be 75 percent below.

The CHAIRMAN. OK. All right.

Mr. Fulkerson, did you have a comment on that?

Mr. FULKERSON. Yes. It seems to me that the low-carbon fuel standard that is being developed in the State of California is one that should be very carefully considered. What it does is, it says, look, by 2017, or whatever, the zero—the fraction of the fuel that you use in your tanks should be 10 percent below what it is today, and it ratchets down from there. It doesn't specify a particular technology, it just simply says that the carbon—the net carbon emissions from that fuel—from the fuel that's used will be cleaner and cleaner with regard to carbon emissions——

The CHAIRMAN. All right.

Mr. FULKERSON [continuing]. And let whatever technology produces it——

The CHAIRMAN. OK.

Mr. FULKERSON [continuing]. Work.

The CHAIRMAN. Very good.

Senator Craig.

Senator CRAIG. Thank you all very much. This is an issue that I know a little bit about, but not a lot, and you've added a great deal to my thought patterns today.

Let me walk you through an interesting scenario that's happening as we speak. We're debating a bill on the floor of the U.S. Senate. In that bill is $0.5 billion for timber-dependent schools and counties. Half a billion a year. OK? In that bill is also $0.5 billion to fight fires. We spent $2 billion last year fighting fires on our public lands. We've got $840 million in Interior approps for firefighting, also. So, we'll spend maybe $1.5 billion fighting fires on our forested lands. You can run the numbers right now. So, we're going to spend a couple of billion dollars a year doing something that we could stop doing if we did something else, but we chose not do that, as a country.

Here is what we're not doing, if you're interested in fiber. Biomass. We've got 100 million tons of dead wood on the floor of our forests today. We're growing 16 million tons a year that are off limits until Mother Nature takes them away in the form of a release of carbon into the atmosphere when she burned 10 million acres last year. Probably the greatest carbon release in the history of our country occurred last year. But, because it was natural, it didn't hit anybody's Richter scale of alarm. But it certainly was carbon.

A healthy forest is a sequestering forest. I'm not sure I understand this picture very well anymore. We're talking about switchgrass and farmers and all of that which is available, and yet, there's 100 million tons laying out there, and 16 million tons a year grown, and we're subsidizing schools and counties because we wouldn't let them touch the forests anymore, and now they're poor. They were once rich. We have tens of thousands of people out of work who once used to work in our forests.

I'm not suggesting getting back to a green sale program, I'm talking about going in and thinning and cleaning and going after the largest quantity of biomass laying out there that Mother Nature is rapidly converting into carbon and sending it into the atmosphere again. You're talking about technologies that, blended with the diversion of $2 billion a year out of our Treasury that we're currently using to fight fires and supplement schools into technology—it would seem to make a lot of sense.

Now, I'm going to suggest you can't get to all of that wood. Wouldn't be natural to, it wouldn't be environmentally sound to do so. But it would certainly be environmentally sound to go after a great deal of it.

What's wrong with that picture?

Yes?

Mr. FULKERSON. There's nothing wrong with that picture. The residues from agriculture and forests are a great source of biomass for energy. You can use the gasification process in order to realize that. So, that's a very good source. There's nothing wrong with that.

Senator CRAIG. Doctor.

Mr. FULKERSON. I mean, you don't want to ruin the forests, but——

Senator CRAIG. No, no.

Mr. FULKERSON [continuing]. As long as you do it carefully.

Senator CRAIG. Well, I look across the landscape of my State today, with thousands of acres dead, bug-killed, can't touch it.

Mr. FULKERSON. Yes.

Senator CRAIG. They're not sequestering one ounce of carbon because they're a dead forest. But a young, viable, diverse stand forest is rapidly grabbing the carbon and putting it into the wood.

Yes, Doctor.

Ms. HERZOG. One thing I firmly believe is not to comment on something I don't know very much about, which is forest science and policy. However, we do have experts in our organization, and I'd love for them to come in and brief you on this issue in detail. There are, from what they believe, environmental impacts from going into forests——

Senator CRAIG. Sure.

Ms. HERZOG [continuing]. And trying to collect all this waste, biomass material, on the ground. So, we actually have put together what we believe are decent sustainability criteria for collecting biomass, which, as I said, I'd love to have our experts——

Senator CRAIG. Yes.

Ms. HERZOG [continuing]. Come in and brief you.

Senator CRAIG. No, entry has impact, there's no question about——

Ms. HERZOG. Right.

Senator CRAIG [continuing]. That. That's a valid thought.

Anyone else wish to comment?

Mr. RATAFIA-BROWN. Senator, the only thing I'd like to say is—I'm not a forestry expert, myself, either. This becomes an economic issue, as far as collection. As I talked, in my testimony, about energy density of wood products is far less than something like coal, you pretty much have to try to increase the density of the material, perhaps on a regional basis, to make it more available to a larger-scale facility.

Senator CRAIG. Well, I appreciate that. But I also appreciate the blending ideas that you're talking about in these new concepts. Would seem to make a good deal of sense.

Mr. RATAFIA-BROWN. No, I agree. I think it's a matter of getting the product to the large-scale——

Senator CRAIG. Yes.

Mr. RATAFIA-BROWN [continuing]. Gasification facility. That is a big issue here. As far as—again, we have a very distributed——

Senator CRAIG. Yes.

Mr. RATAFIA-BROWN [continuing]. Energy source. It's not like coal, that's very energy-dense. Wood and——

Senator CRAIG. Right.

Mr. RATAFIA-BROWN [continuing]. Wood waste is not. You might want to pelletize it, you might want to do something—what we call torrefaction——

Senator CRAIG. Sure.

Mr. RATAFIA-BROWN [continuing]. To increase the energy density. But I agree with your comment.

Senator CRAIG. Thank you.

Did you have a comment, Jim?

Mr. BARTIS. We have also looked at this issue, and we don't—we think small may be beautiful in this case, in that some of concepts for very large plants that are generally associated with coal only, make more sense when we get a lot smaller and look at coal or biomass together. So, this is a——

Senator CRAIG. Yes.

Mr. BARTIS [continuing]. Fantastic opportunity for the research program to look at whether we can do this at a much, much smaller scale, comparable to the scale of typical biomass facilities.

Senator CRAIG. Yes, David.

Mr. DENTON. Yes, I'd just like to add a bit, that biomass is not biomass, that there are different classes of it, just as there are different classes of other feedstocks. Wood waste, in particular, are ones that, because of their nature, may require some different technologies in gasification than others. I know when Polk fed eucalyptus, as well as switchgrass, the switchgrass ran fine. They both gasified fine. The problem was, wood was, you know, getting involved in some of the check valves, plugging up things in those——

Senator CRAIG. It has lignins in it, yes.

Mr. DENTON. There are other issues——

Senator CRAIG. It does create those kinds of problems.

Mr. DENTON. So, it will——

Senator CRAIG. Right.

Mr. DENTON [continuing]. Involve some technology development to probably—but I know there are people looking at that——

Senator CRAIG. Yes.

Mr. DENTON [continuing]. Right now.

Mr. RATAFIA-BROWN. David, that was a relatively minor problem at that facility.

Senator CRAIG. Yes. Well, they do yield differently. Well, thank you all very much for that.

One of the problems we're struggling with here—and certainly the Chairman and I and all of us of this committee have been involved in it—as we've changed the way we manage our forests, we have, in a healthy forest policy, attempted to get in and thin and clean. But there's no value to it. We're not allowed to place a value on it, nor does little value come from it. As a result, we subsidize it, we pay for it with your tax dollars. Therefore, we can't do as much as we ought to be doing in relation to the general health of our forests. The opportunity to add value to it, from that standpoint, in these concepts, seems to be the right dynamic.

But, anyway, thank you all very much for your testimony and your involvement.

The CHAIRMAN. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman. Thank you, to a very interesting panel this morning. I appreciate all that we have heard.

I had an opportunity yesterday to sit down with a group of individuals, primarily from the electric industry, and we were talking about coal and the technologies, and how we move forward with the pilot projects, demonstration projects. Of course, the question that then has to come up is, "It's great to be focused on the technology that is coming, and how we're going to utilize this in the new plants that we build, but what about the existing facilities across the country?" I would like to hear from you this morning whether or not you believe that we have the technology today to help capture and sequester from existing plants through our ability to retrofit. If we don't have the technology, how long until we do have that? What do we do with these existing facilities out there?

Mr. Denton.

Mr. DENTON. Yes. As I mentioned in my testimony, one of the advantages of industrial gasification—I think this is where you can maybe get the jumpstart—is that those technologies, by and large, already require capture of carbon. For example, our facility in Kingsport, we have to capture the CO_2 before it goes forward in our process, any CO_2 that we've formed, primarily due to the shift reaction, where we actually convert some of the carbon monoxide to carbon dioxide while forming more hydrogen for our purposes of chemical use. So, when you do that, you're going to already have carbon capture, so you've got a nice place in an existing facility where you have a concentrated stream of CO_2 that's already captured, so it kind of gets you beyond that first step of two parts of carbon capture and sequestration, the capture and the sequestration, so you're halfway there. So, I think that is a good way to get a headstart on——

Senator MURKOWSKI. So, we're there with the capture. Are we there with the sequestration?

Mr. DENTON. Right. On the sequestration, the good thing is some of the places where, particularly, these industrial plants are being looked at because they're tied to chemical markets, which currently exist, for example, a lot of them, along the Gulf Coast—is your inner region that has, also, a lot of oil recovery development, so there is the potential to look at sequestration in enhanced oil recovery applications. The Gulf Coast also has quite a bit of deep saline aquifer potential, as well. So, you're located in an area that has some good sequestration potential.

Senator MURKOWSKI. What if you're not?

Mr. DENTON. Well, it depends on where you're located. If you're not, then you're going to be looking at what other options you have. If it's coal-based, you may be in a very good location for enhanced coal-bed methane. So, you have to look at all the different options that you have in front of you. But, I think, in most cases, there will be some type of sequestration option. Then the only issue is the cost penalty to go from the captured carbon that you already have to sequestration.

Senator MURKOWSKI. Do we need to be doing more here, from the Federal perspective then, whether it's tax credits or grants—what should we be doing to make sure that the focus is not just on the new facilities that may be coming online within the balance of this next decade, but in retrofitting? Are we doing enough, from a policy perspective? This goes out to anybody.

Mr. DENTON. I think one of the things that has been talked about is the—taking some sort of credit—maybe it's a production tax credit or whatever—to help cover the cost of that sequestration piece. If you had that in place today, folks that already have that captured carbon could be doing something with it and helping advance the technology. So, yes, I think there is a role for incentives for that.

Senator MURKOWSKI. Anybody else?

Mr. Bartis.

Mr. BARTIS. I believe that two things are necessary. First, and most importantly, is to reduce the uncertainties and pass legislation that sets up the framework by which carbon dioxide will be controlled. The sooner we do that, the more we're going to get new plants properly built, and the more we're going to have private industry and all of its innovative capabilities working on the retrofit problem.

Now, with regard to the retrofit problem, that's an extremely important problem. I presume you're talking about the huge investment in existing coal-fired power plants. We do not have technology available today, any means, that allow the capture of carbon dioxide from those existing plants at reasonable cost. It hasn't been proven. At any——

Senator MURKOWSKI. How far away——

Mr. BARTIS [continuing]. Reasonable cost.

Senator MURKOWSKI. How far away are we from that technology?

Mr. BARTIS. I can't tell you that part. I know it's a topic of research, and it's an extremely important research topic in the Department of Energy.

Senator MURKOWSKI. Anybody else?

Mr. Ratafia-Brown.

Mr. FULKERSON. There is a fellow at Carnegie Mellon, Ed Rubin, that has spent a reasonable amount of his career on exactly the question that you're asking, and he would be a really good person to discuss this with. I could certainly put you in touch——

Senator MURKOWSKI. I'd appreciate that.

Mr. FULKERSON [continuing]. With him. I think he can help.

Senator MURKOWSKI. Great.

Mr. Ratafia-Brown.

Mr. RATAFIA-BROWN. Well, let me just say, as far as the technology goes, I agree with Jim, the problem with the capture from an existing coal-fired power plant is that the CO_2 concentration in the plant flue gases is too low. It's not nearly as high as it is in the gasification facility. But there are some ways that one could introduce biomass. It's already done. You want to introduce biomass, like wood products, directly into a boiler, or you—or you use a gasifier prior to the boiler, you gasify the material, and you feed this gasified material right into a coal-fired boiler, so, thereby, gaining the benefit of the biomass use, which effectively reduces your CO_2.

The other technologies that are being worked on are basically using oxygen instead of nitrogen—instead of air, I'm sorry—as the oxidant for these power plants. If you use oxygen, you end up with just CO_2, and, therefore, you have a much higher concentration of CO_2, which will much more effectively allow us to sequester—or capture the CO_2 from existing power plant flue gas. There are a variety of technologies that are being researched through the Department of Energy for this purposes.

So, there are the means. Again, it's a matter of cost-effectiveness and providing more funding for that R&D, but it's doable.

Senator MURKOWSKI. Thank you.

Mr. Chairman, I would suggest that, as we move forward in these areas—there's been a lot of focus on this new technology in the demonstration projects, which is very, very important, but I think we also need to remember as is pointed out, the incredible infrastructure that is already in place, that probably has decades of useful life in them. But if we can't allow for some form of retrofitting, we're not going to be seeing the reductions in emissions that we would like. So, I'd like to work with you on that.

The CHAIRMAN. No, that's a very good point. I appreciate it very much.

Senator Tester, go right ahead.

Senator TESTER. Thank you, Mr. Chairman. I appreciate you holding this hearing. I appreciate the panel to be there. I apologize, I got out of doing the floor thing for a bit to come ask you guys questions.

This issue is critically important to me and—quite frankly, because of the coal reserves we have in Montana. I think there's tremendous opportunity. When I first heard about the coal-to-liquids, I was really, really enthused. Then, the issue of CO_2 started coming up more and more.

I just wanted to ask—as coal-to-liquid related to coal-fired electricity, I might add, it wasn't at a zero-based standpoint. Let's start at the end and work back—if you've got a gallon of petroleum diesel fuel and you've got a gallon of diesel created from coal, and it's burnt in the same vehicle, do they emit the same amount of CO_2?

Go ahead Mr. Fulkerson.

Mr. FULKERSON. The coal-derived liquids would vent twice as much CO_2, approximately.

Senator TESTER. I'm not talking about the process before, in the manufacturing of the fuel, I'm talking a gallon to a gallon burned in the vehicle, we're not doing anything——

Mr. FULKERSON. Oh. Oh, gallon for——

Senator TESTER. Gallon-to-gallon.

Mr. FULKERSON. Same amount. Same——

Senator TESTER. Same amount, OK. As the process goes—well, step backward another time. Now we've taken the coal. It's in gas form. It's my understanding it goes from gas form to liquid form. Is that where the bulk of the CO_2 is generated? It is.

So, Mr. Denton talked about the Eastman Chemical Company. You're taking it from coal to gas, and using it in natural gas form for your processes. How much CO_2 is emitted in that process, compared to coal-fired electrical generation?

Mr. DENTON. Well, in our case, it's a lot less, because keep in mind, we convert a good proportion of the carbon that comes into the feedstock into actual product.

Senator TESTER. OK.

Mr. DENTON. We're trying to convert that carbon into product. We make, as a sidestream, some CO_2, but that is captured by the process.

Senator TESTER. That's good.

I want to step over to Mr. Fulkerson again on—I believe his name is Bob Williams that you're taking the place of. You did a fine job in your presentation, I might add; he's got nothing to be ashamed of there. I couldn't crack the part about biomass negative value and carbon resulting in a negative value in carbon emissions. In other words, in my head, if I plant a tree, and that tree gets big, it absorbs a lot of carbon in that process; I've made a difference in global warming. Now, if I take that tree and I cut it down and I burn it, I haven't done anything from the time I started the tree until I burn it. So, how—and I assume that the process of mixing biomass with coal includes burning that biomass. How can it be a negative value?

Mr. FULKERSON. Well, it's negative, just—the fact is that it takes carbon out of the air to grow the tree or——

Senator TESTER. But don't you release it again in the burning?

Mr. FULKERSON [continuing]. Switchgrass, or whatever, prairie grass, right?

Senator TESTER. Right.

Mr. FULKERSON. OK. Now, you take carbon, and you now sequester it. You put——

Senator TESTER. Yes.

Mr. FULKERSON [continuing]. Put it through the process, and you sequester it.

Senator TESTER. Oh, I see what you mean. You're talking about at the other end. The——

Mr. FULKERSON. Right.

Senator TESTER. OK. So, the question I have is, and I think you said this, so I think you're going to tell me what I already know, but I want to make sure—"Do we have the capability right now to capture carbon on a large-scale basis with the current technology we have?"

Anybody can answer it.

Mr. FULKERSON. Yes, we do have the capability of doing it. But we don't have any large-scale——

Senator TESTER. Demonstrations.

Mr. FULKERSON [continuing]. And storage of carbon from present facilities in the United States.

Senator TESTER. Gotcha. The——

Go ahead.

Mr. BARTIS. We have opportunities to capture carbon from a few plants. The primary opportunity is to use it in enhanced oil recovery. There is a good chance—and there doesn't seem to be any showstoppers available—that we can do geological storage of carbon dioxide. There's also approaches to store carbon—well, I guess coal bed—you can store it in coal seams. So, there's a very low-risk approach, but it's never been demonstrated.

Senator TESTER. OK.

Mr. BARTIS. All right? That demonstration is expensive, but absolutely critical.

Mr. FULKERSON. Senator, there is a demonstration right near you, in North Dakota, and that's the Great Plains process, which sequesters—which doesn't sequester, but it separates out—it sends 160 million cubic feet per day to Saskatchewan to use for enhanced oil recovery.

Senator TESTER. I've gotcha.

Go ahead, Mr. Denton.

Mr. DENTON. Yes. In terms of carbon capture and sequestration, as I mentioned, it is technically feasible. There is no problem. We've been capturing carbon for two decades. As Senator Dorgan mentioned that North Dakota gasification, they are actually putting CO_2 in the ground from enhanced oil recovery. I think the real problem is beyond that. When you beyond enhanced oil recovery, there are issues, beyond technical feasibility, that haven't yet been addressed, and that's stuff like, Who owns the rights, the property rights, to that? Who takes the ultimate liability? What are the requirements by EPA of permitting, say, putting CO_2 into a saline aquifer? There's just a whole lot of other issues around that, that have not been addressed yet, that are the problems right now, not the technical feasibility.

Senator TESTER. So, what you're saying is, we have the technical feasibility to be reasonably sure—because nothing's ever 100 percent, besides death and taxes—but reasonably sure that that CO_2 is going to stay in the ground if we sequester it there?

Go ahead.

Mr. BARTIS. We should be optimistic that that will be the case. That's for one reason—that's the primary reason why RAND suggests we do something with regard to coal-to-liquids. But, until we have multiple large-scale demonstrations——

Senator TESTER. Gotcha.

Mr. BARTIS [continuing]. We're not going to be there.

Senator TESTER. OK.

Mr. BARTIS. None are planned.

Senator TESTER. OK.

I want to talk about water for just a second. I apologize if these are repetitious questions. I want to talk about water, and how much water is required to produce a gallon of coal-to-liquids. Can you give me any idea on how much that would be?

Mr. BARTIS. Yes, I don't——

Senator TESTER. For, let's say, gallon-to-gallon.

Mr. BARTIS. I'll repeat what I said earlier.

Senator TESTER. OK.

Mr. BARTIS. Gallon to gallon, it depends on what you do when you design the plants. If you design the plants in an area that is—that doesn't have lots of—has limited supplies of water——

Senator TESTER. Yes.

Mr. BARTIS [continuing]. You're going to put in certain design features that save water. If you design the plant where water is abundant, you won't put those features in.

So, our best estimate is, for all—the locations that are poor in water, probably 2 gallons of water per gallon of fuel. In areas that are very rich in water, possibly up to 7 gallons of water per gallon of fuel.

Senator TESTER. Does it cost more to—I would assume it would cost more to build the plant that would be water-restrictive.

Mr. BARTIS. Yes.

Senator TESTER. What does that do for competitiveness, as far as barrel of oil?

Mr. BARTIS. I have not looked at those——

Senator TESTER. OK.

Ms. Herzog.

Ms. HERZOG. Yes, I just wanted to—I agree that, obviously, you will have a range, and the technology can be done to reduce water use. Our estimate is, on average, about 5 gallons per——

Senator TESTER. OK.

Ms. HERZOG [continuing]. Per ton of coal, which completely fits into that range.

Senator TESTER. Yes.

Ms. HERZOG. But I'm perhaps a little less optimistic that the best plants will be built in the right places——

Senator TESTER. Yes.

Ms. HERZOG [continuing]. As I'm sure you're aware.

Senator TESTER. Well, I can tell you that, you know, a lot of people have died over water over our history, and it's a critically important piece of survival.

About a month ago, maybe less, with the bill that's going to be on the floor, there was an amendment offered to require—it was a mandate for synfuels—coal-to-liquids. I can't remember what the amount was, but it was fairly significant. There was some difference of opinion as to whether that's the right direction to go, whether to require a mandate first, or to—well, I don't want to put words in your mouth. But what I'm hearing you folks say—and just tell me if this is correct—if you were in my position, the first step you would do, from what I'm hearing, is that you would create a large-scale demonstration project, maybe two or three of them? Is that what I'm hearing? Or am I hearing something else?

Go ahead.

Ms. HERZOG. I'm sure others will jump in with some——

Senator TESTER. Yes.

Ms. HERZOG [continuing]. Technical details, but the—it was 21 billion gallons of liquid coal by 2020—

Senator TESTER. Right, that was it.

Ms. HERZOG. It's approximately 40 medium-sized plants. It was a requirement to be equivalent to gasoline. The key part is the standard associated with the plants. The demonstration plants could make sense, but they have to be doing what we need them to do, which is actually better than gasoline. They have to be doing better, in greenhouse gas life cycle emissions, than gasoline. We would say 20 percent or more.

Senator TESTER. Good point.

Further comments on that point?

Mr. BARTIS. We have looked at this issue, and our view is that we—it's important that we go ahead with a few. I wouldn't call them "demonstrations," but I believe it's very important that we go ahead with a few, where "a few" is up to more politically astute persons than I. But it's important to get progress in this area.

The reason we're saying "a few" is that we haven't—we're not certain about all—how carbon is going to be managed, and we're not certain about the prices of these plants. Now, it's a little unfair that I'm only talking about coal, so to be—to put this in proper context, this all—this same recommendation by RAND would also apply to any incentive that is calling for large amounts of any unconventional fuel, including ethanol fuels. We would say it's premature to do that.

Senator TESTER. OK. Well, you know, it's unfortunate that a person doesn't know more about stuff than you do. You know, as a farmer, I take pride in knowing a lot of stuff about a little, when it comes to making hay or harvesting crops or fixing a combine or whatever. I've always approached this coal-to-liquids from a standpoint that we need to build a foundation, and that foundation revolves around carbon capture and carbon sequestration. It's easy to talk about. I mean, that's pretty straightforward. The question is, "How do you get there? How do you have grants that are applicable for carbon capture and sequestration?" How do you give tax credits? How do you get there? How do you get that research going with the sense of urgency that I truly feel?" Especially after being in Glacier Park last weekend and seeing what's going on there, from a climate standpoint.

Mr. DENTON. I think I mentioned earlier, I think the quickest way still is through some of the industrial gasification opportunities where you already have carbon captured. You don't have to do this, all of it, in an integrated facility. If you're wanting to evaluate carbon capture and sequestration, go to where you already have carbon captured in a cheap way to get that sequestration step proven. If you want to illustrate coal/biomass, you go to where it makes sense to do that. Then you start putting those pieces together, and maybe—and I think there is a value to—at some point, of having a few—as you mentioned—a few of these coal-to-liquids plants with the right kind of configurations to evaluate what you want.

Senator TESTER. Yes, go ahead.

Mr. RATAFIA-BROWN. I would just like to say, with regard to investment tax credits, we run the National Energy Modeling System, the same one that EIA runs, and what I have found with advanced technologies is that, when you do provide that investment tax credit, that incentive, that you can get much earlier penetration of advanced technologies, at least get them in to the marketplace, well before they might otherwise because of that advantage of the lower cost and being able to compete better.

Senator TESTER. OK.

Mr. FULKERSON. You've got to—if you want to solve the problem, you've got to tax carbon emissions. You've got to put an incentive there that sets the market. I assume that that's what all the bills in Congress, and all the debates, are primarily about now, is——

Senator TESTER. Carbon taxes?

Mr. FULKERSON. Yes. Well, carbon——

Senator TESTER [continuing]. Make that——

Mr. FULKERSON [continuing]. Tax, cap-and-trade, whatever. But you've got to put the policies in place that will make people be inventive about the ways in which to meet it.

Senator TESTER. So, what you're saying, until industry gets to a point where they're between a rock and a hard place, they're going to coast?

Go ahead. I mean, you deal with them——

Mr. FULKERSON. That's what I would do.

Senator TESTER. OK.

Mr. BARTIS. I'd like to build upon that statement, though. I mean, I fully agree that it's very important that we put the framework out there. But let's also remember that we have a problem with importing oil from——

Senator TESTER. Oh, yes.

Mr. BARTIS [continuing]. OPEC. We have looked at carbon taxes, or cap-and-trade, where—on valuing carbon dioxide, basically. There is low-hanging fruit out there. The low-hanging fruit is coal-fired power plants, and any centralized use of coal, including these coal-to-liquid plants. But if you put the kind of value on carbon dioxide that motivates capture from these large facilities, you haven't done anything with regard to influencing the problem of imported oil. That carbon tax, a $30 carbon tax, or a $30 cap-and-trade system, that's only going to raise the price of oil about—gasoline about 30 cents. That's not going to motivate much. It's not going to motivate much conservation. So, you need to go beyond just looking—there are two different problems. There's a CO_2 problem, and there's also an energy problem.

Senator TESTER. Yes, I gotcha there.

Ms. HERZOG. Yes. No, I completely agree that just putting a cap on the emission state of transportation fuels won't necessarily drive us to cleaner fuel or vehicle technology. That's why we believe that you actually also need complementary policies to make sure that you expand the fuel sources to be more diverse while meeting certain standards. You can have an oil-reduction standard, you can have a greenhouse gas standard. This would be a low-carbon fuel standard, which would ratchet down over time. This would be greenhouse gas tailpipe emission standards, which would make our vehicles cleaner, as well.

Senator TESTER. Go ahead, Mr. Denton.

Mr. DENTON. Yes, in terms of the topic of taxing carbon, I do want to throw a word of caution here, that, particularly in our industry, we are in a global industry, and we're seeing this daily. We're seeing jobs from the United States go overseas because we are not competing on the energy cost of living in the United States. If you tax, or you do anything that puts a cost to just the U.S. industry, what you're going to see is the actual opposite of what I think you want, that you're going to see those jobs go overseas to operate facilities that are not going to do any of this, and put the emissions into the air. So, we have to be careful about it. I think, start with incentivizing, getting some of these going, until you can get the market in place, get some of these other issues in place, and see a global marketplace that addresses that issue.

Senator TESTER. I understand.

Mr. RATAFIA-BROWN. Yes, I'd like to go back to Senator Murkowski's comment about retrofitting. If you put a heavy tax on carbon, generally what happens is—it's the electricity sector that takes the brunt of it. They are the most elastic, in terms of the ability to control. Again, I've run so many cases of energy bills, looking at different carbon taxes, and what happens is those existing power plants end up being retired very quickly, to the detriment of the industry.

Senator TESTER. I appreciate all of your comments. I will tell you that I think the last thing that anybody on this committee wants to do is increase taxes. But I will also tell you that there has to be a sense of urgency, that I feel in this body, but I don't necessarily feel out in the hinterlands amongst industry. That's not a bad thing about—I'm not badmouthing industry at all. I'm just saying that the folks that are doing the carbon capture, I think, have a tremendous opportunity to make a ton of money by taking that technology, and refining it, and taking it throughout the world.

I hear what each one of you are saying, and I think they all have merits. I appreciate the comments from each one of you. I just want to say this. I appreciate you guys taking the time and coming up here and talking to us truthfully on your lifetimes of experiences dealing with coal and coal-to-liquids and coal-to-gas and the environment. I think we all understand the tremendous opportunity there is here, and also what a tremendous challenge it is to try to make this country energy independent, while satisfying the environmental concerns that are out there.

So, thank you very much.

The CHAIRMAN. Thank you.

Thank you all, again, for coming. This was an excellent hearing, and we appreciate your good advice.

[Whereupon, at 11:40 a.m., the hearing was adjourned.]

APPENDIX

Responses to Additional Questions

RESPONSES OF DAVID DENTON TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. You testified about the relative ease, compared to IGCC, that industrial gasification facility could get to 90% capture of feedstock carbon. This would seem to present a real opportunity to make progress on lifecycle emissions compared to natural gas as a feedstock if biomass is incorporated in a substantial way. How much opportunity is there to incorporate biomass into the process?

Answer. Gasification technology is relatively feedstock flexible and thus certainly has potential for incorporation of biomass as a feedstock. But this potential is dependent upon the type of biomass and upon the specific gasification technology that is used. For example, biomass used in slurry-fed gasifiers must be in a form suitable for use in the high-pressure slurry pumps used to feed the gasifiers. One must also keep in mind that biomass feedstocks have only been demonstrated to date as relatively minor co-feeds in commercial-scale gasifiers. Feed of significant quantities of biomass to a commercial-scale gasifier would require a step increase in overall project risk, an increase that may be difficult to project finance until a few commercial-scale demonstrations have occurred. For example, it is highly likely that biomass and coal feedstocks, if co-fed to a gasifier, would react at different rates (i.e., one of the feedstocks would react with oxygen faster than the other, resulting in over-oxidation of one feedstock and under-oxidation of the other), making control of outlet syngas composition more difficult. Feed of significant quantities of biomass to commercial-scale gasifiers also faces other market and risk issues that have not yet been resolved, such as obtaining long-term (20+ years) assured supply of large quantities (up to thousands of tons per day) of adequately dried and stored biomass within a reasonable (50-mile or less) radius of the gasification facility and at an acceptably low long-term feedstock price. Industrial gasification projects already face multiple siting issues—e.g., being close to an inexpensive coal/petcoke feedstock source, close to markets for the desired end products and to acceptable outbound logistics, and close to suitable long-term carbon dioxide sequestration reservoirs. Adding a further requirement to be sited near suitable biomass feedstock supplies could severely limit the options for siting such facilities. However, to the extent that selected sites can accommodate biomass feedstocks, opportunity does exist to pursue such co-feeds over time as the above-mentioned market and risk issues are addressed.

Question 2. If you do feed biomass into a coal gasification process what kind of reductions in lifecycle emissions do you estimate would be achievable as compared to other fossil fuel feedstocks?

Answer. Lifecycle gasification emissions of any feedstock are dependent upon the composition of the feedstock and upon the design of the syngas cleanup process. These variables are somewhat independent, so it would be difficult to say what, if any, overall lifecycle emission reductions might occur by co-feeding biomass. To the extent, however, that any carbon dioxide formed in the process is sequestered, the overall lifecycle emissions of carbon dioxide to the atmosphere would be reduced if one includes the extraction of carbon dioxide from the atmosphere by the growing biomass.

RESPONSES OF DAVID DENTON TO QUESTIONS FROM SENATOR SANDERS

Question 3. The Intergovernmental Panel on Climate Change has recently issued its Fourth Assessment Report Summary for Policy Makers. In that Report they concluded that the evidence that global warming is real and caused by humans is unequivocal. The MIT study, "The Future of Coal," suggested that Carbon Capture and Storage (CCS) may increase the cost of electricity from coal by 20%, but an aggressive energy efficiency campaign could be conducted, so that less electricity is used, bringing our electricity bills down by 20% or more. What do you see as the cost of liquid fuel (diesel) and gaseous fuel from coal and/or coal-biomass with CCS versus conventional diesel and natural gas in the near term and long term?

Answer. Eastman has not yet had occasion to conduct a detailed calculation of the cost of diesel and synthetic natural gas with CCS. There have been studies reported by others, such as the DOE, which reference such cost comparisons. However, the percentage of added cost for CCS would be expected to be less for products such as diesel and synthetic natural gas (methane) than for electric power, because the processes required to produce diesel fuel and methane, just as with other industrial gasification processes, already incorporate capture of most of the carbon dioxide formed in the process, whereas capture of the carbon dioxide would be an added step for production of electric power. As technologies such as coal-to-liquids and coal-to-methane are commercialized and deployed, one can reasonably expect the costs to produce such products to drop over time as the processes are improved and first-of-a-kind risks are reduced.

Question 4. I join Senator Murkowski in her concern about the need to retrofit our existing coal fired power plants to address the issue of carbon capture and storage. Some of the testimony suggested that adding "oxyfuel" to these older plants would be the best path to take as this burns pure oxygen, instead of outside air, producing a carbon dioxide-rich exhaust stream, with little or no NO_X, so the CO_2 is more concentrated and easier to capture for sequestration. Do you have any information on the ease/feasibility of retrofitting older coal plants or other coal-burning industrial facilities with "oxyfuel"?

Answer. Eastman has not directly evaluated "oxyfuel" combustion as a retrofit for existing coal-fired power plants. However, one could reasonably assume that "oxyfuel" retrofit of existing boilers could be problematic because most of these boilers were not designed to be air-tight. Any in-leakage of air to older boilers would introduce nitrogen diluent into the system and defeat, to some extent, the purpose of adding "oxyfuel" combustion. So the success of "oxyfuel" retrofit of existing boilers could be dependent upon how well the boilers can be sealed to prevent such in-leakage of air. Also, it is not at all clear that introduction of pure oxygen to boilers would not result in substantial increases in NO_X emissions from such boilers (due to higher flame temperatures) without the addition of a substitute diluent such as recycled carbon dioxide. In addition, one would still need to remove sulfur and other contaminants from the exhaust gas prior to sequestration of the carbon dioxide (for most such applications), and it is unclear what retrofits would be required to those existing downstream cleanup steps (such as scrubbers) to enable "oxyfuel" retrofit of the main boilers. However, the proponents of "oxyfuel" combustion are working to try and address all of these issues.

RESPONSES OF DAVID DENTON TO QUESTIONS FROM SENATOR SALAZAR

Question 5. It appears from the written testimony, that liquid fuels produced from coal combined with biomass can result in lower greenhouse gas emissions than conventional gasoline. What are the technology hurdles to overcome in mixing biomass with coal to produce liquid fuels? Has the combination of biomass and coal been used at any commercial plant? What is a realistic percentage of greenhouse gas emissions compared to petroleum that we can expect to achieve?

Answer. See the response to question No. 1 above.

Question 6. Even with the use of biomass, there are still substantial volumes of CO_2 that must be captured and safely stored. Are there any recommendations this panel has on where to locate CTL facilities to facilitate the storage of CO_2?

Answer. To facilitate the storage of CO_2, one must be near an adequately-sized geologic reservoir suitable for long-term storage of the CO_2. The DOE (Office of Fossil Energy/NETL), through cooperation with its Regional Carbon Sequestration Partnerships, has recently developed a Carbon Sequestration Atlas that identifies a number of suitable geologic reservoirs across the United States and Canada. Obviously, the most economic CO_2 storage alternatives would involve sequestering the CO_2 in productive applications such as enhanced oil recovery or enhanced coal bed methane.

Question 7. Can you discuss the water requirements for a CTL plant? Are there opportunities for reusing/recycling water in the process?

Answer. Eastman has not yet calculated the water requirements for a CTL plant. Depending on the composition of various water streams, there may be opportunities to recycle or reuse some of the water streams, such as in preparation of coal-water slurries to feed to the gasifiers. However, such recycle or reuse may require treatment of the water stream to remove specific impurities that might otherwise build-up in the recycle stream.

Question 8. The auto industry has developed plug-in electric hybrids, and this committee has heard testimony about all-electric cars. Can you discuss the advantages and disadvantages of using coal to produce liquid fuels vs. using coal to generate electricity to charge batteries for electric cars and hybrids?

Answer. Both alternatives offer opportunities to utilize coal to reduce our dependence on foreign oil for transportation. Both alternatives will likely be required to utilize coal to address energy security. The decision that determines which alternative is preferred may depend on whether, for a specific site and application, it is more cost effective to logistically transport liquid fuels or to transmit electric power from the gasification facility. It also depends on the ultimate transportation mode—for example, there are no current electric-powered commercial or military aircraft (except for small drones). From a greenhouse gas emissions standpoint, the less complex alternative may be to produce electric power coupled with CCS because it avoids the added complication of co-feeding biomass to achieve emissions reductions below that of conventional fuels production and use. But as mentioned above, both alternatives will be required to adequately address our overall energy security needs through utilization of coal.

RESPONSES OF DAVID DENTON TO QUESTIONS FROM SENATOR DOMENICI

Question 9. How important is a secure domestic source of feed stock to the chemical industry in this country?

Answer. If the chemical industry is to survive in this country, it must have a long-term secure source of low, and relatively stable, priced feedstocks and energy. Industrial gasification of domestic coal, petroleum residues (such as petcoke), biomass, and recycled secondary materials can help address this need. The run-up in energy prices, and the resultant volatility in energy prices, from natural gas and petroleum since the year 2000 has contributed to the loss of over 100,000 jobs in the U.S. chemical industry alone (an overall job reduction of over 10% in that timeframe). Other energy-dependent industries, such as fertilizers, glass, steel, and forest products, have also been dramatically impacted. These high-technology and well-paying jobs are being exported to other countries that have lower and more stable energy and feedstock costs.

Question 10. The National Energy Technology Laboratory has indicated it is technologically and economically feasible to produce 22,000 barrels of liquid naphtha (NAP-THA) per day and 27,800 barrels of diesel product per day from 24,500 tons of Illinois No. 6 coal while producing 124 mega-watts of electricity to the grid and capturing 32,500 tons of carbon dioxide per day.

Answer. It is certainly technically feasible to gasify coal and co-produce diesel, naphtha, and electricity while capturing carbon dioxide. Economic feasibility depends on a number of factors, not the least of which are the competing price of conventional diesel fuel and the costs associated with capital project construction. Appropriate government incentives can be effective at reducing the impact or uncertainty of these economic variables.

Question 11. Can you give us an estimate of the total domestic demand for naphtha from the chemical industry in this country?

Answer. According to the DOE's Energy Information Administration, over 100 million barrels of naphtha were supplied for total U.S. petrochemical feedstock uses in 2006 (over 300,000 barrels of naphtha per day).

Question 12. Assuming questions about further reducing carbon dioxide could be answered, at approximately what price per gallon would the naphtha have to be produced from a coalto-liquids process for the Chemical Industry to shift away from foreign natural gas or foreign LNG?

Answer. The price would have to be sustained at some discounted level below the projected long-term market price of naphtha and/or the market-equivalent price for naphtha substitutes such as natural gas or LNG. It would also have to be at a price sufficient to enable the U.S. chemical industry to be competitive with global sources for the naphtha-derived end products. Naphtha prices (for petrochemical feedstock uses) typically track crude oil prices with about a 5% to 10% added cost (for example at an oil price of $40 per barrel, naphtha could be expected to have a market price of around $42 to $44 per barrel).

RESPONSES OF DAVID DENTON TO QUESTIONS FROM SENATOR THOMAS

Question 13. What specific technology gaps need to be closed by DOE and private industry working together to reduce the technical and economic risk of coal-derived fuel plants?

Answer. The most important technology gaps are to demonstrate CTL technologies using actual U.S. coal-based syngas, to reduce the overall capital cost of

CTL processes (including air separation, gasification, syngas cleanup, carbon capture, and any syngas-tofuels conversion technologies), and to improve the overall fuel yields of CTL processes.

Question 14. In addition to financial incentives, in the form of tax credits, appropriations, and other tools at Congress' disposal, what regulatory approaches do you believe can be taken to advance the development of a domestic coal-derived fuel industry? Please address not only liability issues associated with carbon dioxide sequestration, but permitting of the actual plants, obstacles to construction of infrastructure, and other issues that you believe could be addressed from a regulatory, rather than a financial, standpoint.

Answer. Regulatory incentives could include certification of CTL fuels, accelerated permitting of CTL plants, long-term liability for geologic storage of carbon dioxide, and requirements for utilization of CTL fuels in the transportation sector (civilian, military, and strategic petroleum reserves).

Question 15. Does the use of a FT coal-derived diesel product have an improved footprint for nitrous oxide, particulate matter, sulfur dioxide, volatile organic compounds, and mercury over traditional sources of diesel? Please quantify the per gallon differences for criteria pollutant emissions that would result from consumption of a FT coal-derived diesel product versus traditional, petroleum-derived, diesel fuel.

Answer. Fischer-Tropsch coal-derived diesel would be ultra-low in sulfur content and mercury and would bum cleaner than conventional diesel fuel (lower NO_X, PM, etc.). The Department of Defense has compared emissions of F-T jet fuels versus conventional jet fuels. Similar improved emission results should be expected from F-T diesel fuels.

Question 16. China is aggressively pursuing development of a CTL industry. If the U.S. does not, is it possible that we will be importing CTL fuels from China in the future?

Answer. That is certainly a possibility, although current Chinese CTL production is targeted at satisfying their rapidly-growing domestic market.

Question 17. What implications does this have for U.S. national security?

Answer. Increasing reliance on foreign sources for our supplies of petroleum, natural gas (LNG), fuels, chemicals, fertilizers (i.e., food), and other industrial products has definite implications for our overall national security, including our energy security, food security, job security, and technological/industrial/manufacturing superiority. Without utilization of our abundant domestic resources, such as coal via gasification, all of these are at increased risk over the long-term.

Question 18. We are told that Fischer-Tropes fuels require no modifications to existing diesel or jet engines, or delivery infrastructure including pipelines and fuel station pumps. Is that true?

Answer. Eastman has not evaluated this issue sufficiently to comment. However, it is known that South Africa has successfully used F-T coal-derived fuel blends for over half a century to help address its transportation needs utilizing conventional engines and infrastructure.

RESPONSES OF WILLIAM FULKERSON TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. The facilities that are commonly talked about here are very large and use significantly more coal than a comparable coal-fired power plant. If one were to blend in biomass on the levels you advocate how much biomass are we talking about for a typical plant? Is it realistic to assume enough could be produced in the area of the facility?

Answer. This is a good question. Bob Williams and his colleagues at Princeton have made detailed calculations for a plant supplied by switchgrass and Illinois bituminous coal that uses oxygen blown gasification and captures and stores CO_2 derived from both the switchgrass and the coal (CCS). The size of the plant they considered would supply 1030 MW of synthetic gasoline and diesel (about 18,000 barrels per day of gasoline equivalent) plus 460 MW of electric power. These products would be manufactured from 2200 MW [7700 dry tonnes/day (dt/d)] of coal plus 900 MW (4500 dt/d) of switchgrass. To grow this much switchgrass would require about 500 square miles of land assuming a yield of 10 dry tonnes per hectare per year (t/ha/y) and an annual plant capacity factor of 80%. This would be 15% of the land within a 33-mile radius of the plant. As you can see building and operating such a plant would be no small undertaking, but the biomass growing and gathering effort would appear to be quite manageable.

A key characteristic of this plant is that the net fuel-cycle-wide greenhouse gas emission rate associated with producing and consuming the synthetic liquid fuels would be about 27% of the rate for the petroleum-derived fuels displaced. In addition, the co-product electricity is produced in a high-efficiency combined cycle power plant at a carbon emission rate that is only about 10% of that for a new coal power plant that does not have CCS.

Alternatively, Williams points out that mixed prairie grasses grown on carbon-deficient soil might be used as the biomass feedstock. In this case carbon is taken from the atmosphere both to grow the harvested prairie grass and to build up significant additional carbon in the soil and roots. (See Tilman, David, et al. Science, 314, 1598-1600, December 8, 2006). Taking into account this extra sequestration Williams calculates that the amount of biomass required to reduce to zero the fuel cycle wide GHG emission rate associated with the production and consumption of the liquid fuels produced in such a plant would be about 3400 t/d requiring about 390 sq mi of land to grow. For such a plant the biomass and coal inputs account for 21% and 79% of fuel energy input, respectively. The energy and carbon flows for this system are shown in the attached figure.

Williams' bio-coal system has the flexibility to accommodate a wide range of cellulosic feedstocks, including crop residues (e.g., corn stover and wheat straw) and forest product industry residues (e.g., logging residues) as well as dedicated energy crops.

The coal gasifier and Fisher-Tropsch synthesis parts of the technology are fully commercial. The biomass technology is less well developed. Use of separate gasifiers for biomass and coal at the conversion plant may ultimately prove to be the least-costly approach; the needed large-scale biomass gasifiers for this approach are not yet commercial but could be commercialized by 2015 with a focused development effort. For the near term, some commercial coal gasifiers can be co-fired with modest amounts of biomass. In The Netherlands, the Nuon IGCC power plant at Buggenum has been fired for about a year with biomass accounting for 11% of the fuel energy input along with coal. Plans are to increase the percent of energy input from biomass to 20% during 2008.

The biomass used in these systems will be much more costly than the coal (on a $ per million btu basis), and that will be good for the farmer. Nevertheless the calculations carried out by Williams and his colleagues show that if GHG emissions were valued or taxed at $25 to $30 per tonne of CO_2 equivalent, these zero or near-zero GHG emitting Fisher-Tropsch liquids could be produced from coal + biomass with CCS at lower cost than Fischer-Tropsch liquids derived from only coal with either CO_2 vented or with CCS. This remarkable economic finding arises from the huge credit realized from subsurface storage of photosynthetic CO_2 that offsets the coal-derived carbon emissions from the plant and from combustion of the fuel products.

An additional important benefit of this bio-coal fuels scheme is that more liquid fuel is produced per Btu of biomass than from the cellulosic ethanol process, for example—in fact, 2-3 times as much. This is due primarily to the fact that most of the energy to run bio-coal plant comes from the coal. In the manufacture of cellulosic ethanol nearly all the energy to produce ethanol comes from the biomass and hence more biomass energy is required per Btu of fuel product. Since the limiting factor in the production of liquid fuels from biomass is the biomass resource, the comparatively high productivity of the bio-coal process is very important. Additionally less coal energy is used which reflects back into less mining and associated environment and safety impacts.

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RESPONSES OF WILLIAM FULKERSON TO QUESTIONS FROM SENATOR SANDERS

Question 2. The Intergovernmental Panel on Climate Change has recently issued its Fourth Assessment Report Summary for Policy Makers. In that Report they concluded that the evidence that global warming is real and caused by humans is unequivocal. The MIT study, "The Future of Coal," suggested that Carbon Capture and Storage (CCS) may increase the cost of electricity from coal by 20%, but an aggressive energy efficiency campaign could be conducted, so that less electricity is used, bringing our electricity bills down by 20% or more. What do you see as the cost of liquid fuel (diesel) and gaseous fuel from coal and/or coal-biomass with CCS versus conventional diesel and natural gas in the near term and long term?

Answer. Energy efficiency should be the first and foremost strategy pursued both for managing climate change and for reducing oil insecurity. I fully agree with the MIT report (MIT, 2007)[1] on this point as well as the U.S. Climate Change Technology Strategic Plan and the IEA Energy Technology Perspectives of 2006. In addition the National Commission on Energy Policy Study points out the importance of efficiency in transportation for reducing oil dependence.

Regarding synthetic liquid fuels production, consider first a coal to liquids plant with full CCS (capturing 85-90% of the CO_2 not contained in the energy products). With this much CCS, the fuel cycle-wide GHG emission rate for the production and consumption of liquid fuel would be about the same as for the crude oil-derived products displaced. For these plants CO_2 capture is relatively straightforward because most of the coal-derived carbon that is not contained in the produced synfuels is vented at the conversion facility as a relatively pure stream of CO_2. As a result, the capture cost is very low—essentially the cost of drying and compressing CO_2 to make it ready for delivery to an underground storage site. The cost of CO_2 transport and storage would be comparably low if storage were in depleted oil or gas fields or in deep saline formations. If there were an opportunity to use the CO_2 for enhanced oil recovery (EOR), the incremental cost for CCS could be negative—i.e., the value of the CO_2 for this purpose would often be more than the cost of capturing the CO_2 and delivering it to the EOR site.

(Note: A question that has arisen regarding CO_2 EOR is whether the purchased CO_2 actually stays put. It has been estimated that less than 1% of the CO_2 purchased for CO_2 EOR has escaped into the atmosphere (Stevens and Eppink, 2001),[2] but prior to the Beulah/Weyburn project [CO_2 produced at the Beulah ND Great Plains Synfuels Plant and piped 250 miles north for EOR in the Weyburn oil field in Saskatchewan, Canada] emissions from CO_2 EOR projects have not been routinely monitored. The Beulah/Weyburn project has been intensively monitored by a broad international scientific consortium, and no CO_2 emissions have been detected (IEA GHG R&D Programme, 2005).[3] Moreover, modeling carried out for this project has estimated that over the next 5000 years less than 0.2% of the injected CO_2 would escape to the biosphere.

Recent studies carried out by the National Energy Technology Laboratory (NETL) and Nexant researchers (Olson and Reed, 2007; Reed and Olson, 2007)[4] analyzed a 50,000 barrels per day (2900 MW_1) synfuel plant producing a small amount of coproduct electricity (86 MW_e). They found that with CO_2 vented such a plant could provide investors with a 20% rate of return on equity when the oil price is about $60 a barrel. They estimated that including CO_2 capture would increase the capital cost by only about 2% and reduce the electricity output to 24 MW_e. They estimated that capture and aquifer storage of the CO_2 would become cost completive with CO_2 venting when the CO_2 emissions value is of the order of $15 per tonne. Such a plant with CCS would produce liquid fuels with net carbon emission rates similar to that for the production and use of petroleum based fuels.

Carbon emissions can be further reduced to zero or near zero by coprocessing enough biomass with coal (as described in the answer to Q. 1) and sequestering the CO_2 produced. The sequestration of the carbon from the biomass offsets the coal-derived carbon emitted in the plant and from burning of the fuels produced. However, biomass is a more expensive feedstock than coal, so the cost of producing Fischer-Tropsch liquid (FTL) fuels will be greater than for a straight FTL coal plant until the CO_2 emissions value is sufficiently high. Williams and his colleagues at Princeton estimate that in the range of $25-30 per tonne of CO_2 emissions value the bio-coal plant could provide synthetic fuels at lower net cost than for synfuels derived

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[1] Deutch, J., and E.J. Moniz et al., The Future of Coal: Options for a Carbon-Constrained World, an Interdisciplinary MIT Study, 2007.

[2] Stevens, S., and J. Eppink, *CO_2* Utilization for Enhanced Oil and Gas Production, Gasification Technologies 2001, San Francisco, 9 October 2001.

[3] IEA GHG R&D Programme, IEA *GHG Weyburn CO_2* Monitoring & Storage Project, Petroleum Technology Research Centre of Canada, 2005.)

[4] S.C. Olson (Nexant) and M.E. Reed (NETL), "Impacts of Future US GHG Regulatory Policies on Large-Scale Coal to Liquids Plants," paper presented at the *6th Annual Conference on Carbon Capture and Sequestration,* Pittsburgh, PA, 7-10 May 2007, to be published in the Proceedings of the Conference.

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from coal only with CO_2 vented or with CO_2 captured and stored (see also the answer to Question No. 1). This emissions value is in the ballpark estimated in the MIT coal study and many other studies as needed to begin to incentivize CCS from coal fired power plants. Without controlling emissions from coal fired power plants around the world mitigating climate change will be much more difficult, so a climate change policy should value CO_2 emissions at least this much.

Question 3. I join Senator Murkowski in her concern about the need to retrofit our existing coal fired power plants to address the issue of carbon capture and storage. Some of the testimony suggested that adding "oxyfuel" to these older plants would be the best path to take as this burns pure oxygen, instead of outside air, producing a carbon dioxide-rich exhaust stream, with little or no NO_X, so the CO_2 is more concentrated and easier to capture for sequestration. Do you have any information on the ease/feasibility of retrofitting older coal plants or other coal-burning industrial facilities with "oxyfuel"?

Answer. I do not have the information you seek, but I do know an expert in the field who can probably answer this very interesting question. He is Ed Rubin of Carnegie Mellon University in Pittsburgh PA. I sent this information to Senator Markowski already.

In general there are two approaches to reducing emissions of CO_2 from existing coal fired power plants. The first is to scrub the stack flue gases to absorb the CO_2 and sequester it. The second approach is to fire the power plant boilers with oxygen and coal to produce relatively pure CO_2 flue gas without nitrogen, and then sequester it. Both of these approaches have been tried. They are not simple or inexpensive. If one is contemplating a new coal facility, the IGCC route with CCS will likely be the best approach depending on coal properties and special circumstances.

The National Energy Technology Laboratory (NETL) has estimated that flue gas scrubbing will increase in the cost of electricity in the range of 45 to 70%. Advanced systems may bring this cost penalty down to about 20%. For the oxyfuel process the cost escalation is estimated to be 26 to 50% and with advanced systems in the range of 20%. The IGCC process with CCS would be in the range of 19 to 31% and with advanced systems in the range of 5–10%. The energy penalty is about 30% for a pulverized coal plant and 16% for an IGCC plant using current technologies.

RESPONSES OF WILLIAM FULKERSON TO QUESTIONS FROM SENATOR SALAZAR

Question 4. It appears from the written testimony, that liquid fuels produced from coal combined with biomass can result in lower greenhouse gas emissions than conventional gasoline. What are the technology hurdles to overcome in mixing biomass with coal to produce liquid fuels? Has the combination of biomass and coal been used at any commercial plant? What is a realistic % of greenhouse gas emissions compared to petroleum that we can expect to achieve.

Answer. One hurdle involves the handling of various biomass feedstocks. These were addressed by Jay A. Ratafia-Brown of SAIC at the hearing. Jumping these hurdles will require some development work and first class engineering, as I understood Jay's comments. My impression from what Jay said was that there were no real showstoppers, however.

Another hurdle involves biomass gasification. There are two alternative approaches to cofiring coal and biomass: one involves use of separate gasifiers to make the synthesis gas from which the liquid fuels are made, followed by a blending of the synthesis gas streams from coal and biomass for further processing. Alternatively, coal and a modest amount of biomass could be gasified in the same gasifier. Only the latter approach is viable with commercially available coal gasifiers, and co-gasification is much more difficult for some commercial coal gasifiers than for others.

The 250 MWe IGCC plant at Buggenum in The Netherlands has been coprocessing 11% biomass and 89% coal (on an energy basis) for about a year, and plans are to increase the biomass percentage to 20% during 2008. If that same gasifier fired with 11% biomass were used to make synthetic liquid fuels instead of electricity, the greenhouse gas (GHG) emission rate for the liquid fuels would be 20-25% less than the rate for the crude oil-derived hydrocarbon fuels displaced. This is an emissions rate that is similar to that from manufacturing corn ethanol. The co-gasification route uses cellulosic biomass instead of food biomass, thereby avoiding the corn, meat, and fertilizer price escalations that have accompanied the rush to ethanol.

The coprocessing of cellulosic biomass with coal in this manner represents a much quicker route to establishing cellulosic biomass in the energy market than the cellulosic ethanol route, because, as remarked by Dan Reicher (former DOE Assistant Secretary for EE/RE): "Producing cellulosic ethanol is clearly more difficult than we thought in the 1990s" (*New York Times, 17 April 2007*). Moving quickly to coal/biomass coprocessing would be very helpful in evolving a logistics infrastructure for cellulosic biomass.

The separate gasifiers approach would make it feasible to increase the biomass fraction enough to reduce the net GHG emission rate to zero for liquid fuels. Realizing zero net emissions this way would require only ⅓ to ½ as many biomass Btus per Btu of liquid fuels as is required in making cellulosic ethanol. If there were a concerted development effort the separate gasifiers approach could likely be fully commercial by the middle of the next decade. This should in no way decrease our efforts to convert cellulose to ethanol or other fuels biochemically. Cellulosic ethanol has the advantage that no CCS is needed.

Question 5. Even with the use of biomass, there are still substantial volumes of CO_2 that must be captured and safely stored. Are there any recommendations this panel has on where to locate CTL facilities to facilitate the storage of CO_2?

Answer. Yes, in the biomass/coal plant considered by Williams and his colleagues some 4.5 to 5 million tonnes of CO_2 would need to be stored each year. For the same amount of fuel produced changing the relative amounts of coal and biomass inputs doesn't affect very much the amount of CO_2 that would be available for capture and storage, but adding more biomass makes the net carbon emissions to the atmosphere much less because the biomass-derived CO_2 stored underground was taken out of the atmosphere in growing the biomass.

Currently, DOE is conducting 7 regional assessments of sequestration opportunities. These cover the country. Good opportunities exist in many places, particularly where deep saline aquifers are available, and also in many regions where the CO_2 can be used for enhanced oil recovery.

As the MIT study emphasized, several storage projects storing at least a million tonnes of CO_2 annually are needed to understand better the outlook for aquifer storage in different types of geological reservoirs and to provide a solid scientific and engineering basis for the CO_2 storage regulatory regime for the longer term. CTL plants would be good candidate sources for providing the needed CO_2 for some of these early storage projects, because the CO_2 capture cost is low—much less than the cost for CO_2 capture at power plants.

The low CO_2 capture cost at CTL plants also makes these attractive candidates for CO_2 enhanced oil recovery projects.

Siting bio-coal fuel plants requires access to adequate biomass and coal supplies as well as sequestration capacity. One possible site for a needed full-scale demonstration of bio-coal fuels production providing liquid fuels with zero or near-zero net lifecycle carbon emissions might be in southern Illinois, near the hypothetical site picked by Bob Williams for his recent study, because all the needed resources are there.

A full-scale demonstration of a bio-coal fuels plant could be organized between the government and the private sector in the next 5-10 years.

Question 6. Can you discuss the water requirements for a CTL plant? Are there opportunities for reusing/recycling water in the process?

Answer. No, I cannot answer this question, but as I recall, Jim Bartis from RAND at the hearing suggested about 7 gallons of water per gallon of fuel is in the right ballpark. Williams agrees with this rough estimate. Most of the water is for evaporative cooling; a minor fraction is consumed in the process.

The availability of hydrological water supplies could be a constraint on the extent of deployment of synfuels technologies, especially in arid regions of the West. There evaporative cooling water requirements could be dramatically reduced shifting to dry cooling towers. Reducing process water requirements would be more challenging. But even in arid regions of the West there are substantial supplies of saline water deep underground—fossil water that is not involved in the hydrological cycle. Williams has estimated that the physical volume of process water required is comparable to the physical volume of CO_2 that must be stored underground for synfuel plants that practice CCS. He has suggested investigation of the concept of recovering saline water and desalinating it for process use, and injecting for underground storage CO_2 plus the salt-rich residual of the desalination process.

Question 7. The auto industry has developed plug-in electric hybrids, and this committee has heard testimony about all-electric cars. Can you discuss the advantages and disadvantages of using coal to produce liquid fuels vs. using coal to generate electricity to charge batteries for electric cars and hybrids?

Answer. It depends upon what you mean by plug-in hybrids. The problem is that we don't have a proper battery for such a vehicle. The energy density is too low by a factor of 2 to 3, and the battery life is too short under deep discharge conditions needed to maximize the usefulness of a plug-in hybrid. Great progress is being made, but batteries are not there yet. This is what I have been told by Venkat Shrinivasan of Lawrence Berkeley National Lab.

When a proper battery becomes available using electricity to augment liquid fuels in transportation is a great idea. If off-peak power is used which is the logical strategy, the cost of electricity will be low. Also, because the efficiency of charging a battery is high as is the efficiency of electric drive electricity can be a very competitive energy source. Even with the current fraction of fossil derived electricity, use of the plug-in hybrid will probably reduce carbon emissions. Michael Kintner-Meyer of Pacific Northwest National Laboratory has estimated this.

Nevertheless, one still needs fuels to run a hybrid and the bio-coal fuels process provides a way to produce conventional liquid transportation fuels with zero or near zero net emissions from the whole fuel cycle.

My conclusion is that we should work hard on better Li-ion batteries and bio-coal liquid fuels.

RESPONSES OF WILLIAM FULKERSON TO QUESTIONS FROM SENATOR THOMAS

Question 8. You mention that coal and biomass gasification is a very promising technology that requires additional development, especially on biomass collection and preparation. What are the advantages that accompany waiting until this technology is commercial before imposing limits on the allowable carbon dioxide footprint?

Answer. As I have already noted in my answer to question No. 4, one variant of the concept (based on co-gasification of modest amounts of biomass along with coal) can be introduced with current technology, whereas a system based on use of separate gasifiers needs further development.

And as I have already noted, getting started via the co-gasification route would be very helpful in evolving the logistics infrastructure for cellulosic biomass via learning by doing and in beginning a transition from food biomass (e.g., corn, soybeans) to cellulosic biomass in the production of liquid fuels.

I will give you my opinion as to how public policy might be used to encourage both this early experience and a transition to more advanced technologies.

As there are already technologies near-at-hand for reducing the carbon footprint of synfuels production and use, measures promoting deployment of reduced carbon technologies are needed. But in crafting a deployment policy, it would be wise to frame the policy so as to drive us toward mitigating climate change and reducing oil insecurity simultaneously without the government's attempting to pick technological winners.

One approach to a policy for technology deployment would be to tax fuels on the basis of net carbon emissions (on a total fuel cycle basis). Obviously, such a carbon management policy would create a level playing field and would avoid the government pick winning problem. With such a policy, bio-coal fuel would be taxed much less than petroleum based fuels. A tax would give the consumer the right signals and industry as well. Most of the tax might be returned to the public to avoid hardships.

California is trying a very interesting alternative approach. They will develop regulations requiring a gradual reduction in the carbon intensity of transportation fuels. This would penalize fuels from petroleum or coal without co-processing biomass and without sequestration. It would establish a strong market for low carbon and carbon neutral fuels such as the bio-coal fuel proposed by Williams (or cellulosic ethanol for example).

Of course, a technology deployment policy, whatever its form, should be complemented by measures aimed at bringing to commercial readiness advanced concepts (e.g., bio-coal systems based on separate gasfiers for coal and biomass). So two parallel paths are needed in public policy.

Question 9. In addition to financial incentives, in the form of tax credits, appropriations, and other tools at Congress' disposal, what regulatory approaches do you believe can be taken to advance the development of a domestic coal-derived fuel industry? Please address not only liability issues associated with carbon dioxide sequestration, but permitting of the actual plants, obstacles to construction of infrastructure, and other issues that you believe could be addressed from a regulatory, rather than a financial, standpoint.

Answer. I am not an expert on this the topic of regulations. However, in answer to Q 8 a low carbon fuel standard is one regulation that should be explored carefully, and it is being considered seriously by California. With time a greater and greater fraction of fuel would be required to be low or no net carbon emitting fuel on a total fuel cycle basis. This could be formulated in a way that does not legislate technologies. Over time it would create a premium for such fuels that would feed-back to creating supply options. Dr. Antonia Herzog of NRDC also suggested such a fuel standard at the hearing I believe.

On the issue of liability associated with CO_2 storage or transport I assume liability insurance should be required and that safety of pipelines and sequestration sites should be regulated by the states or the Federal government. Of course, pressurized CO_2 is commonly piped over considerable distances for enhanced oil recovery and the retention of the CO_2 in those deposits appears good. See my response to question 2.

In my judgment coal synfuels plants should not be built without the requirement that excess CO_2 be captured and stored (CCS), and the bio-coal fuels process suggested by Williams with CCS is the best option suggested so far to tame the remaining evils of coal while optimizing the use of biomass.

In my opinion if we want to reduce oil insecurity and also mitigate climate change a carefully conceived set of policies are needed some involving financial sticks and carrots and some involving regulatory tools. The six policies listed at the end of my testimony might be a good start, and I copy them here.

First, the greenhouse gas emission externality must be reduced by putting a cost on emissions by cap and trade or tax or whatever. The Congress through various pieces of proposed legislation is actively considering this, and no doubt something will emerge.

Second, a low-carbon fuel standard such as is being developed by the State of California should be adopted and existing subsidies on low carbon fuels should be discontinued.

Third, regulations should be adopted to assure that no new coal synfuels plants are built without carbon capture and storage.

Fourth, an oil security feebate might be enacted to put a floor on transportation fuel prices. If oil prices crash, say to \$30/bbl from \$60, transportation fuel could be taxed and part of the tax rebated to synfuels plants to help them compete and produce even with low world oil prices. Part of the tax revenues could be returned to the public.

Fifth, regulations (such as improved CAFE standards) to promote more efficient use of transportation fuels need to be aggressively strengthened over time.

Sixth, regulations and R&D to improve coal mine safety, worker health, and environmental improvement need to be periodically reviewed and upgraded if necessary.

However, as I mentioned in my testimony it is relatively easy to make such a list. The hard work comes in sorting out the many options so policies invented are effective, fair, and politically possible. That is the difficult task facing this Committee and the Senate in the whole.

Question 10. What specific technology gaps need to be closed by DOE and private industry working together to reduce the technical and economic risk of coal-derived fuel plants?

Answer. The principal gap relates to CO_2 storage. The extent to which CTL and coal in general have substantial futures in a carbon-constrained world depends critically on the future prospects for secure CO_2 storage.

We are not likely to be able to learn much more than we already know about this potential by doing more paper studies and small-scale experiments. Rather, a number of "megascale" projects (each storing a million tonnes of CO_2 annually or more)[1] in a variety of geological media, with an emphasis on deep saline formations, are needed as soon as possible both to understand the true practical potential for secure storage and to help define the regulatory regime needed for "gigascale" CO_2 storage (MIT, 2007).

CO_2 capture costs are much less for CTL plants than for coal power plants. The low cost of CO_2 capture at CTL plants makes such plants strong candidates for providing low-cost CO_2 for early megascale storage projects that can be very helpful in closing the gap. With regard to Williams' bio-coal fuels idea coal gasification and Fischer-Tropsch technologies are commercially ready. But there is much less experience with biomass. Large biomass gasifiers must be commercialized.

Also, as I commented in the answer to Q 4 that development is needed in the preparation of biomass feedstocks of various sorts for the oxygen blown gasification step. Jay A. Ratafia-Brown of SAIC addressed these at the hearing.

Question 11. Does the use of a FT coal-derived diesel product have an improved footprint for nitrous oxide, particulate matter, sulfur dioxide, volatile organic compounds, and mercury over traditional sources of diesel? Please quantify the per gallon differences for criteria pollutant emissions that would result from consumption of a FT coal-derived diesel product versus traditional, petroleum-derived, diesel fuel.

[1] For perspective, the CO_2 storage rate for a 50,000 barrels per day CTL plant would be 8 to 9 million tonnes per year.

Answer. Emissions of NO_X, unburned hydrocarbons, and particulates from the burning of F-T diesel in compression ignition engines tend to be lower than from burning petroleum-derived diesel fuel (Norton et al, 1998).[2] In addition, the S content of F-T fuels would be extremely low. This is because sulfur is a FT catalyst poison so it must be removed upstream of the FT units at the fuel processing plant.

For coal-derived F-T liquids mercury would also have to be removed at the processing plant but it can be removed at very low incremental cost.

The regulations developed or being developed for Diesel fueled vehicles including 18-wheelers should apply to FTL as to petroleum-derived fuels.

Question 12. China is aggressively pursuing development of a CTL industry. If the U.S. does not, is it possible that we will be importing CTL fuels from China in the future?

Answer. Sure, it is possible that we will someday import CTL fuels from China. This is not likely to occur unless petroleum based fuels are more expensive. What we should be working to prevent is a CTL industry in China without capture and storage of the excess carbon. A U.S. low carbon fuel standard would provide an incentive for China to practice carbon capture and storage and bio-coal fuel production.

Question 13. What implications does this have for U.S. national security?

Answer. Coal synfuels are being advanced mainly because of energy supply insecurity concerns associated with dependence on oil imports and because of the prospect of sustained high oil prices. But whatever the U.S. does to enhance energy security by promoting CTL must be carried out in ways that simultaneously mitigate climate change. Because of the national security risks inherent in GHG emissions-induced climate change, energy security concerns do not trump climate change concerns—as pointed out recently by a blue-ribbon panel of retired US admirals and generals from the Army, Navy, Air Force, and Marines (CNA, 2007).[3]

RESPONSES OF JAMES BARTIS TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. You advocate both for carbon capture and gasification of biomass with coal to meet greenhouse gas emissions targets. Using both together, you indicate there is a level where the total lifecycle emissions could theoretically be zero or even negative. Assuming that is with further technological development, what do you think are achievable standards today for percentage of carbon captured, biomass included, and lifecycle emissions?

Answer. For first-of-a-kind CTL plants built in the United States, 80 percent capture of all plant CO_2 emissions is an achievable standard. This level of reduction should result in lifecycle emissions that are between 10 and 20 percent higher than motor fuels produced from conventional petroleum. This level of capture is consistent with the two lowest risk approaches for managing carbon in initial coal-based commercial plants, namely, co-firing of coal and biomass and the use of carbon dioxide for enhanced oil recovery. This emission factor is also appropriate for CTL plants that would capture carbon dioxide for use in a long-term demonstration of geologic sequestration.

This percentage reduction is possible without forcing a CTL plant to incorporate gas turbines that can accept a fairly pure hydrogen feed. Adding such turbines would allow at least 95 percent removal; however, it is our judgment that requiring hydrogen turbines would add considerably to the market uncertainties associated with the future course of world oil prices and the technical uncertainties associated with building, operating, and capturing carbon from a first-of-a-kind plant.

Question 2. You advocate that any facilities that receive federal incentives should be at least comparable in greenhouse gas emissions to petroleum-derived fuels. Our recent renewable fuels bill included a standard requiring fuels have 20% less lifecycle emission than the fuels they replace. How feasible would a similar standard be for coal-derived fuels?

Answer. Once initial production and carbon management experience is obtained, a similar, or even tighter standard, is feasible for fuels produced from a blend of coal and biomass. Such a standard is not feasible for the initial round of commercial plants because of the uncertainties discussed in the response to Question 1 above. Such a standard is also not feasible for plants that use only coal as a feedstock. The

[2] P. Norton, K. Vertin, B. Bailey, N.N. Clark, D.W. Lyons, S. Goguen, and J. Eberhardt, "Emissions from Trucks Using Fischer-Tropsch Diesel Fuel," Society of Automotive Engineers Paper 982526, 1998.

[3] CNA Corporation, National Security and the Threat of Climate Change, Alexandria, Virginia, 2007.

best that coal-only plants can achieve is parity with conventional petroleum-based fuels.

This question raises a broader issue regarding implementing energy policy objectives, namely, the efficacy of emission standards for first-of-a-kind fuel plants that are subsidized by the government. The proposed legislation is not intended to obtain early production experience but rather to promote strategically significant amounts of production. But for coal-to-liquids, as well as biomass-derived fuels based on Fischer-Tropsch or cellulosic conversion, what is most needed is initial commercial production experience. For the case of coal-based plants, such initial experience should include attaining reasonably achievable levels of carbon management, as discussed in the response to Question 1. Setting standards for lifecycle CO_2 emissions may be more appropriate once that initial experience is achieved.

RESPONSES OF JAMES BARTIS TO QUESTIONS FROM SENATOR SANDERS

Question 3. The Intergovernmental Panel on Climate Change has recently issued its Fourth Assessment Report Summary for Policy Makers. In that Report they concluded that the evidence that global warming is real and caused by humans is unequivocal. The MIT study, "The Future of Coal," suggested that Carbon Capture and Storage (CCS) may increase the cost of electricity from coal by 20%, but an aggressive energy efficiency campaign could be conducted, so that less electricity is used, bringing our electricity bills down by 20% or more. What do you see as the cost of liquid fuel (diesel) and gaseous fuel from coal and/or coal-biomass with CCS versus conventional diesel and natural gas in the near term and long term?

Answer. I confine my answer to diesel from coal, since RAND does not yet have available useful estimates on the costs of diesel from coal-biomass. Also, our research has not addressed the production of natural gas from unconventional resources.

As I testified, there are significant uncertainties regarding the costs of constructing and operating a first-of-a-kind coal-to-liquids production facility. There are also large uncertainties associated with the costs of developing and operating a facility for carbon sequestration. Using available design data, we estimate that the costs to produce a gallon of diesel from initial coal-to-liquid plants will be between \$1.40 and \$1.70 per gallon, assuming no carbon management. This is a plant gate cost, and should be compared to a refinery gate price, which for diesel is currently between \$2.00 and \$2.10 per gallon. Once the first commercial plants are operating and experience-based learning begins to take place, costs should drop below \$1.40 per gallon.

With carbon capture and geologic sequestration, we estimate that the above cost range will increase to \$1.60 to \$2.10 per gallon. The broad range of all of our cost estimates reflects the fact that they are derived from highly conceptual engineering designs intended to provide only rough estimates of liquid fuel production costs and the cost uncertainties regarding geologic sequestration. We are also concerned that the recent large cost increases associated with the construction of major capital intensive projects are not adequately reflected in the above estimate. It is for these reasons that we recommended in our testimony that Congress consider cost-sharing options that would promote the development of a few site-specific designs that will provide reliable cost estimates.

For some carbon management options, such as using carbon dioxide in enhanced oil recovery, the operators of coal-to-liquids plants may be able to sell their carbon at a price that recovers the extra costs associated with capturing, compressing and delivering it to the user's site. In this case, the costs of producing liquid fuels would be close to, or slightly lower than, the estimated costs without carbon management.

The above ranges refer to production costs, including a reasonable return on investment. The actual prices will be based on future wholesale prices for diesel fuel (which is based on the world oil price and refining margins) and could be significantly lower or higher.

Question 4. I join Senator Murkowski in her concern about the need to retrofit our existing coal fired power plants to address the issue of carbon capture and storage. Some of the testimony suggested that adding "oxyfuel" to these older plants would be the best path to take as this burns pure oxygen, instead of outside air, producing a carbon dioxide-rich exhaust stream, with little or no NO_X, so the CO_2 is more concentrated and easier to capture for sequestration. Do you have any information on the ease/feasibility of retrofitting older coal plants or other coal-burning industrial facilities with "oxyfuel"?

Answer. The feasibility of retrofitting older coal plants is an extremely important issue. Because RAND has not yet had the opportunity to investigate this problem, I am not able to provide you with an informed answer.

RESPONSES OF JAMES BARTIS TO QUESTIONS FROM SENATOR SALAZAR

Question 5. It appears from the written testimony, that liquid fuels produced from coal combined with biomass can result in lower greenhouse gas emissions than conventional gasoline. What are the technology hurdles to overcome in mixing biomass with coal to produce liquid fuels? Has the combination of biomass and coal been used at any commercial plant? What is a realistic percentage of greenhouse gas emissions compared to petroleum that we can expect to achieve?

Answer. The most efficient and economic gasifiers that are currently available for use in a Fischer-Tropsch system are entrained-flow gasifiers. Such gasifiers operate at pressures of about 30 atmospheres (450 pounds per square inch) and require a finely-sized feed, which is either blown or sprayed into the gasifier. The technical challenge is to devise the system that grinds, pressurizes, and feeds a stream of biomass or a combination of biomass and coal into the gasifier with high reliability and efficiency. This is a fairly minor technical challenge. It is an engineering problem focusing on performance and reliability, not a science problem. To establish the design basis for such a system requires the design, construction, and operation of one or a few test rigs. These test rigs need to be fairly large so that they are handling flows close to what would be the case in a commercial plant. This is because solids are involved and it is very difficult to predict performance and reliability of solids handling and processing systems when the size or throughput of the system undergoes a large increase. Such large-scale testing could be conducted during the design and construction of a full-scale plant for co-firing coal and biomass.

Combinations of biomass and coal have been used in commercial plants in the past, but only at low biomass-to-coal ratios and with a limited number of biomass types. I believe the highest ratio used in continuous gasifier operations was at the Nuon IGCC power plant in The Netherlands, which was mentioned by Mr. Jay Ratafia-Brown in his testimony on May 24. This plant used a biomass-to-coal ratio (energy input basis) of about 1 to 5. Whereas much higher ratios, about 1 to 1, would be needed to bring carbon emissions to well-to-wheels parity with petroleum-derived fuels, assuming no carbon capture and sequestration. Additionally, the Nuon plant did not use the types of biomass that are estimated to be most abundant in the United States.

The relative percent reduction of greenhouse gas emissions that can be achieved via combined biomass and coal use depends on the fraction of the feed that is biomass as compared to coal. Consider liquid fuel production plants without carbon capture and sequestration. At one extreme, imagine a plant that is fed only biomass. Greenhouse gas emissions are generated in cultivating, harvesting and transporting biomass, but these emissions are fairly small, so that using fuel from a biomass only plant would likely entail lifecycle greenhouse gas emissions that are less than 10 percent of those from conventional petroleum-based fuels. As we add coal to the plant, the lifecycle greenhouse gas emissions increase. At a 50-50 mix, the emissions levels would be comparable to conventional petroleum, and would increase to about 2.0 to 2.3 times conventional petroleum for plants using just coal.

The preceding discussion applies to liquid fuel production plants without carbon capture and sequestration. With carbon capture and sequestration, a 50-50 mix of biomass and coal should yield lifecycle greenhouse gas emissions that are close to zero. As the biomass ratio increases, the lifecycle emissions would become negative, and as the coal ratio increases, net emissions would increase until they reached a maximum that would be very close to that associated with conventional petroleum.

Question 6. Even with the use of biomass, there are still substantial volumes of CO_2 that must be captured and safely stored. Are there any recommendations this panel has on where to locate CTL facilities to facilitate the storage of CO_2?

Answer. RAND has not conducted research on the geologic and technical issues associated with site selection of facilities for the storage of CO_2, and therefore cannot provide an informed response to the main thrust of this question. We strongly recommend that the U.S. government take measures as soon as possible that are required to conduct multiple large-scale demonstrations of geologic sequestration at various sites across the United States. In addition to geologic and technical issues, the site selection process should consider proximity to major coal resources. We also recommend that the site selection process should promote extensive public participation, including inputs from state and local governments, industry, and non-governmental organizations.

Question 7. Can you discuss the water requirements for a CTL plant? Are there opportunities for reusing/recycling water in the process?

Answer. RAND has conducted research on water consumption and production in Fischer-Tropsch plants that use natural gas as a feedstock to produce liquid fuels. Based on this research, we estimate that at least 1.5 barrels of water would be consumed in a CTL plant for each barrel of liquid product produced. By consumed, we mean water either used to make hydrogen or lost through evaporation. We assume that no once-through cooling water is used. To obtain the minimum water usage, the plant would need to install dry cooling towers and incorporate extensive measures to minimize water losses in the power generation and oxygen production portions of the plant. The net result of designing such a plant would be an increase in investment costs and a reduction in the operating efficiency of the plant. As a result, such a plant would only be built in areas in which water, including suitable groundwater, was in very limited supply.

In areas in which water is abundant, we anticipate that as much as 10 barrels of water would be consumed in a CTL plant for each barrel of liquid product produced. Such a plant would likely use less expensive evaporative cooling towers. The change from dry cooling towers to evaporative cooling accounts for most of the additional water losses. The remaining losses are associated with less recycling of process water.

For most CTL plants, the water consumption will fall between 1.5 and 7 barrels of water per barrel of liquid product produced, with the actual amount depending on the cost, availability, and quality of local water supplies.

Question 8. The auto industry has developed plug-in electric hybrids, and this committee has heard testimony about all-electric cars. Can you discuss the advantages and disadvantages of using coal to produce liquid fuels vs. using coal to generate electricity to charge batteries for electric cars and hybrids?

Answer. With progress in technology, electric vehicles and plug-in hybrids could be cost effective as alternatives to conventional fuels and a means of reducing greenhouse gas emissions. At present, however, the status of battery technology is such that all-electric cars are expensive and limited in acceleration and range, and therefore have a very limited market in the United States. Likewise, shortfalls in current battery technology limit the ability of plug-in hybrids to offer significant fuel savings at reasonable costs, especially compared to current and emerging non-plug-in hybrids.

If the battery problems can be overcome, the extent to which greenhouse gas emissions would be reduced would still depend on the CO_2 emissions associated with producing the electricity used to charge the batteries. If the electricity is produced from fossil fuels, these emissions could be mitigated with carbon capture and sequestration.

Whether and when sufficient progress in battery technology will occur remains an open question. As such, electric cars and plug-in hybrids, as well as hydrogen-powered vehicles, are research concepts that are deserving of federal support. However, it would be imprudent to delay measures to address global climate change or energy security based on the prospect that any of the advanced concepts are the "silver bullet."

RESPONSES OF JAMES BARTIS TO QUESTIONS FROM SENATOR THOMAS

Question 9. In terms of emissions, your testimony focuses on greenhouse gases. There are many other substances, however, that Congress has deemed appropriate to regulate and reduce. They include mercury, sulfur dioxide, nitrous oxide, particulate matter, and others.

Answer. None received.

Question 10. How do coal-derived fuels perform in these categories relative to the conventional fuels that they will replace?

Answer. This answer address emissions that would occur at the plant site at which coal-derived liquids would be produced. The answer to Question 11 addresses emissions from the use of the fuel.

The front end of an F-T coal-to-liquid fuel production plant is very similar to power plants that would be based on coal gasification. The primary difference is that the F-T catalysis reactor is extremely sensitive to trace amounts of mercury and sulfur, so that extensive removal of compounds containing these elements will occur before the synthesis gas is allowed to enter the F-T reactor.

For mercury, we anticipate that commercially available mercury control systems can capture between 90 and 95 percent of the mercury that would otherwise enter the F-T reactor. This would reduce net plant mercury emissions to between 5 and 10 percent of the level that would result if the same amount of coal were burned in a conventional power plant.

For sulfur, commercially available removal systems are able to reduce sulfur concentrations to parts per billion. Net emissions of all gaseous sulfur compounds to the atmosphere would be negligible, namely, well under a hundredth of what would be released by a modern power plant meeting current standards and burning the same amount of coal.

With regard to particulate emissions, these would come from various sources within a CTL plant. Without recourse to a front-end engineering design, we are unable to provide a numerical estimate. However, it is our judgment that, given the performance of commercially available equipment for controlling emissions, particulate emission levels are unlikely to be a deciding factor on the ability to site a CTL plant.

The only significant sources of nitrogen oxide emissions are the gas turbines used to produce power used within the CTL plant and for sale. The amount of fuel consumed by the gas turbines can vary significantly based on how the CTL plant is designed. A reasonable range for a CTL plant is that 70 to 150 MW of gas turbine capacity will be in operation for each 10,000 barrels per day of liquids production capacity. Nitrogen oxide emissions from these units should be comparable to the state of the art for turbines designed for combined-cycle power plants designed for natural gas or coal.

Question 11. Specifically, does the use of F-T coal-derived diesel products have an improved footprint for nitrous oxide, particulate matter, sulfur dioxide, volatile organic compounds, and mercury over traditional sources of diesel? Please quantify the per gallon differences for criteria pollutant emissions that would result from consumption of F-T coal-derived diesel products versus traditional, petroleum-derived, diesel fuel. China is aggressively pursuing development of a CTL industry. If the U.S. does not, is it possible that we will be importing CTL fuels from China in the future? What implications does this have for U.S. national security?

Answer. Published test data indicate that using F-T-derived diesel fuel in existing heavy and light duty diesel engines yields reduced emissions of nitrogen oxides, particulate matter, sulfur oxides, and volatile organic compounds as compared to ultra-low sulfur diesel fuel derived from petroleum. Reported reductions are generally in the range of 15 percent for nitrogen oxides and between 25 to 50 percent for particulate matter. Somewhat greater levels of nitrogen oxide and particulate matter reductions are possible in engines modified or specifically designed for F-T fuel use. While F-T fuel has less than a tenth of the sulfur of the typical ultra-low sulfur diesel fuel currently being sold, we do not anticipate a full ten-fold or greater reduction in sulfur oxide emissions, since other sources of sulfur, such as lubricating oil, become noticeable contributors at these very low levels. We are still evaluating the literature results for volatile organic compounds and carbon monoxide. The results that we have already seen indicate no significant changes. Vehicular fuel use, including gasoline and diesel, is not viewed as an important source of mercury emissions.

Both the national security and economic interests of the United States would benefit from China's development of a CTL production capability. By using China's coal resources to produce CTL, China will need to import less fuel from the Middle East. This should lead to lower world oil prices and thereby, savings to all oil users, including American users, and lower export revenues to OPEC members, a number of whom are governed by regimes that do not support American foreign policy objectives.

It is highly unlikely that China will export CTL fuels since even a very large CTL industry in China is unlikely to be able to meet the shortfall between China's domestic production of crude oil and its demand for liquid fuels.

Question 12. CTL fuels are the only currently available "drop in" replacements for military and civilian aviation fuel. Civilian aircraft flying in and out of Johannesburg, South Africa have been using CTL fuels for years. What specific actions do you believe Congress can and should take to facilitate development of a U.S. CTL industry to assist the U.S. aviation industry?

Answer. RAND research shows that the benefits of developing a CTL industry in the United States do not accrue to any specific types of fuel users, but rather to all fuel users, including military and civil aviation. This is because the main benefit of producing any unconventional fuel is that it reduces demand for conventional petroleum and thereby reduces world oil prices.

Coal-derived liquids have certain performance properties that allow them to command a premium price in certain markets. In particular, because CTL fuels are nearly free of sulfur and have a very high cetane number, CTL fuels will command a premium when used as automotive and truck fuels. But these two characteristics offer less value when considering aircraft applications. As such, we believe that commercial aircraft are not a likely market for CTL fuels produced in the United States over the foreseeable future.

Our finding is that any federal actions to promote CTL use in commercial aircraft would not be productive. The critical path for CTL development is obtaining initial commercial operating experience and use in automotive applications.

Question 13. Mr. Fulkerson testified that "If the excess CO_2 produced is sequestered instead of vented then the coal synfuels process can be equivalent to petroleum in net CO_2 emissions." Ms. Herzog's testimony seems to dispute this. How do we reconcile these differences of opinion?

Answer. At RAND, we have conducted extensive research on this topic. Our analyses show that net CO_2 emissions from CTL plants with sequestration range from slightly less than to slightly more than petroleum. What drives the differences in our calculations are assumptions regarding the degree of carbon capture (the last few percent of removal costs much more than the first 95 percent on a $ per pound basis), the efficiency of the CTL plant, and the emissions associated with the refining of conventional petroleum. Additionally, most CTL plants co-generate electric power. This electric power will displace a conventional power plant. Assumptions regarding whether the displaced power would be from an uncontrolled coal-fired power plant or from a plant using carbon capture and sequestration also influence how CTL emissions are calculated.

Question 14. In addition to financial incentives, in the form of tax credits, appropriations, and other tools at Congress' disposal, what regulatory approaches do you believe can be taken to advance the development of a domestic coal-derived fuel industry? Please address not only liability issues associated with carbon dioxide sequestration, but permitting of the actual plants, obstacles to construction of infrastructure, and other issues that you believe could be addressed from a regulatory, rather than a financial, standpoint.

Answer. A great deal of research suggests that the most cost-effective approach for addressing both energy security and greenhouse gas reduction is through a broadly applied market-based approach that stimulates changes in energy production and consumption through increases in the costs of using petroleum-derived energy and through increases in the costs of energy uses according to their greenhouse gas emissions. An example of this approach would be an energy security tax on all petroleum-derived liquid fuels and a tax on all fossil energy fuels based on their net greenhouse gas emissions, taking into account any reductions in emissions from sequestration. This approach would help to level the playing field among different energy forms based on their potential energy security and greenhouse gas impacts. Under this approach, a domestic coal-derived (or coal and biomass-derived) fuel industry would develop to the extent that such a fuel lifecycle was economically advantageous over other options, taking into account the security and greenhouse gas taxes.

Before this or any other approach based on financial incentives can be effectively applied, however, we believe that the government needs to support early, but limited commercial operating experience for coal-based liquids production so that both industry and government are better prepared to act wisely as further information becomes available regarding world oil prices, the viability of carbon capture and sequestration, and the future requirements associated with addressing energy security and greenhouse gas emissions. The approach we are recommending is somewhat akin to insurance, or paying for an option to make a future investment even if it is decided later that the investment is not needed. For this measured approach, we see a need for financial incentives, but we see no need, at this time, for special legislation or regulatory actions to accelerate permitting or to address obstacles to construction of infrastructure.

I am unable to provide an informed comment on the regulatory issues associated with siting and operating carbon dioxide sequestration facilities, since neither I nor others at RAND have conducted sufficient research on this topic.

Question 15. What specific technology gaps need to be closed by DOE and private industry working together to reduce the technical and economic risk of coal-derived fuel plants?

Answer. In my testimony, I listed four important measures that the federal government can take, in cooperation with industry, to reduce the uncertainties in the costs and performance of coal-derived fuel plants. The first of these measures is to cost-share in the development of a few site-specific front-end engineering designs of commercial plants based on coal or a combination of coal and biomass. The second is to foster early commercial experience by firms with the technical, financial, and management wherewithal to successfully bring a project to fruition and most importantly to capture and exploit the learning that will accompany actual operations. The third of these measures is to conduct multiple demonstrations and, by way of such demonstrations, develop the regulatory framework required for a commercial sequestration industry. And the fourth of these measures is to support research, development, testing and evaluation of concepts for integrating coal and biomass for the production of liquid fuels. An early low-risk, high-payoff opportunity in this last area is the construction and operation of test rigs and/or pilot plants for evaluating the performance subsystems for co-feeding coal and biomass into entrained-flow gasifiers.

Question 16. I have been told that coal-derived fuels have a higher cetane level. Please explain the benefits, environmental and otherwise, that are to be derived from that fact.

Answer. The *cetane number* is a measure of how readily diesel fuel ignites. The higher the cetane number, the sooner a fuel will start to burn after it is injected into the combustion chamber. Coal-derived fuels from the Fischer-Tropsch process will generally have a cetane number from 70 to 80. This is significantly higher than refinery diesel, which generally ranges from 40 to 55.

In general, fuels with higher cetane numbers make starting a cold engine easier and reduce hydrocarbon and soot pollutants generated in the minute or so following a cold start. Higher cetane number fuels also tend to reduce NO_X and particulate emissions, although the amount of such reductions is dependent on engine design.

Fuels with high cetane numbers are generally lower in aromatics. Coal-derived fuels based on the Fischer-Tropsch method have extremely low levels of sulfur and aromatics and these two attributes offer improved environmental performance with regard to both particulate and hydrocarbon emissions and should extend the operating life of catalytic converters used to remove pollutants from diesel exhaust.

Question 17. We are told that Fischer-Tropsch fuels require no modifications to existing diesel or jet engines, or delivery infrastructure including pipelines and fuel station pumps. Is that true?

Answer. This is true, so long as additives are allowed. In general, the additive package would be similar to that associated with conventional fuels intended for use in diesel or jet engines. For unblended (i.e., 100 percent Fischer-Tropsch liquids) coal-derived fuels, additional additives may be required to assure adequate lubricity and to protect seals.

RESPONSES OF ANTONIA HERZOG TO QUESTIONS FROM SENATOR SANDERS

Question 1. I am very supportive of your suggestion that we can better power our vehicles with electricity, whether generated by coal or renewable electricity like solar and wind, rather than converting the coal to liquids and using that liquid fuel in our internal combustion engines, which are much less efficient than electric motors. You pointed out that plug-in hybrid electric vehicles (PHEVs) powered by coal-based electricity with CCS are about 10 times better than Coal To Liquids (CTL) with CCS used in a regular hybrid vehicle when it comes to CO_2 emissions. You also concluded that PHEVs using coal-electricity with CCS are twice as good as Coal to Liquids with CCS in terms of oil displaced, that is, I presume the same as the amount of distance that can be traveled with the same ton of coal. These are important findings. Can you please share with us the underlying assumptions for those calculations? Your suggestion that the PHEV will travel 3.14 miles/kwh, for example, is based on what tests or studies? Some have suggested that PHEVs can do even better by going 5 or 6 miles/kwh.

Answer. Attached is a spreadsheet with the basic calculations behind these results.*

As you noted, our conclusion is that a ton of coal used in a power plant employing carbon capture and storage (CCS) to generate electricity for a plug in hybrid vehicle will displace more than twice as much oil and emit one-tenth as much CO_2 per mile driven as using the same coal to make liquid fuels in a plant that uses CCS.

The analysis used the vehicle efficiency assumptions (37.1 miles/gal, 3.14 miles/kWh) are from the just released EPRI-NRDC Joint technical Report, *Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions* (1015325), July 2007. See the report for a more detailed discussion of the analysis (http://www.epri-reports.org/ and http://www.epri-reports.org/Volume1R2.pdf).

One assumption in our spreadsheet that is not quite consistent with the EPRI modeling is the assumption that PHEVs operate on electricity 75% of the time. We believe the number is probably closer to 50%.

Question 2. I understand that PHEVs at the efficiency you suggest would use 10 kwhs to go 31.4 miles or, at 10 cents per kwh, about a dollar for 31 miles, versus what a gasoline car would pay for 31 miles of travel, over $3. Is that accurate? If

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* Information has been retained in committee files.

PHEVs are charged at cheaper night-time rates, what is the cost equivalent per gallon of fuel? I have heard that it is less than one dollar per gallon. If we consider that PHEVs will most likely be charged by a mix of fuels that are cleaner than coal, like natural gas, hydro, and others, what is the CO_2 comparison today, without CCS with a PHEV to a regular hybrid fueled by CTL fuel without CCS? Do your figures consider the total life cycle CO_2 emissions, that is, do they include energy costs from transportation, storage, pumping of the liquid fuels and other energy costs in the CTL numbers?

Answer. The calculation you present is correct. Again I refer you to the joint NRDC-EPRI study (http://www.epri-reports.org/Volume1R2.pdf) mentioned in Q1 for a detailed discussion of the full lifecycle (well-to-wheels) GHG emissions for PHEV for different mix of fuels (Figure 5-1). There is also NRDC's plug-in hybrid factsheet which can be found at, http://www.nrdc.org/energy/plugin.pdf.

For PHEVs, per mile global warming emissions are greatly affected by what is used to charge them. Today's typical pulverized coal plant (2.5 pounds CO_2e/kWh) results in the highest emissions, about 7.25 lbsCO_2e/mi. The average grid (1.3 pounds CO_2e/kWh) is a mix of generation sources mainly coal, natural gas, nuclear and large hydro resulting in about 5.5 lbsCO_2e/mi. Non-emitting renewable electricity sources such as wind, geothermal, and solar provide the lowest emissions per mile, about 3.5 lbsCO_2e/mi. This analysis assumes all vehicles travel 12,000 miles per year. On-road efficiency for conventional vehicles is 24.6 miles per gallon while hybrid drivetrains achieve 37.9 mpg on gasoline. PHEV electrical efficiency is 3.2 mi/kWh and 49% of the PHEV miles are using stored grid energy. Much of the PHEV charging occurs during the night (see Figure 4-5).

Question 3. The Intergovernmental Panel on Climate Change has recently issued its Fourth Assessment Report Summary for Policy Makers. In that Report they concluded that the evidence that global warming is real and caused by humans is unequivocal. The MIT study, "The Future of Coal," suggested that Carbon Capture and Storage (CCS) may increase the cost of electricity from coal by 20%, but an aggressive energy efficiency campaign could be conducted, so that less electricity is used, bringing our electricity bills down by 20% or more. What do you see as the cost of liquid fuel (diesel) and gaseous fuel from coal and/or coal-biomass with CCS versus conventional diesel and natural gas in the near term and long term?

Answer. The MIT report estimates the costs of Fischer-Tropsch liquid fuel and synthetic natural gas from coal with and without CCS, see p. 156-157, Table A-3.F.2. They estimate that the F-T fuel production cost is $50/bbl without CCS and $55/bbl with CCS. The production cost of SNG is estimated to be $6.7/million BTU without CCS and $7.5/million Btu with CCS. We believe these estimate are on the low end. Furthermore, an economic study by Jim Dooley of Battelle (Jim Dooley, Robert Dahowski, Marshall Wise, Casie Davidson "Coal-to-Liquids and Advanced Low-Emissions Coal-fired Electricity Generation," presentation at NETL conference, May 9, 2007, PNWD-SA-7804) predicts that in a carbon constrained world CTL would not be a competitive fuel even with CCS.

Question 4. I join Senator Murkowski in her concern about the need to retrofit our existing coal fired Power plants to address the issue of carbon capture and storage. Some of the testimony suggested that adding "oxyfuel" to these older plants would be the best path to take as this burns pure oxygen, instead of outside air, producing a carbon dioxide-rich exhaust stream, with little or no NO_X, so the CO_2 is more concentrated and easier to capture for sequestration. Do you have any information on the ease/feasibility of retrofitting older coal plants or other coal-burning industrial facilities with "oxyfuel"?

Answer. Combustion with pure oxygen instead of air eliminates the nitrogen, avoids production of nitrogen oxides during combustion, and produces an exhaust gas with a very high CO_2 concentration, making it easy to capture through simple compression and cooling. The main operating cost of this system comes from the operation of the air separation unit. Oxy-fuel PC combustion is in early commercial development but appears to have considerable potential. It is under active pilot-scale development, and larger projects are under consideration, with a decision pending by the board of Saskpower at the end of July whether to proceed with a 300MW unit.

Currently, an oxyfuel retrofit seems to be a more economically attractive option than a retrofit with post-combustion capture system (e.g. amine scrubbing). The recent MIT study on the Future of Coal confirmed this point (p. 148). It is possible, however, that in a decade or two a more attractive option through post-combustion capture might exist, although there is no guarantee. It is at least as likely that oxyfuel will be the retrofit technology of choice, or that there will be no unanimous choice and that the optimum choice will depend on the specifics of a particular plant.

The study also stated clearly that "retrofitting an existing coal-fired plant originally designed to operate without carbon capture will require major technical modification" (p. xiv). Moreover, no such retrofits have been performed. Constructing a new plant with capture from the outset makes engineering and economic sense, and we should minimize our reliance on retrofits as much as possible by designing and building all new plants with capture.

RESPONSES OF ANTONIA HERZOG TO QUESTIONS FROM SENATOR SALAZAR

Question 5. It appears from the written testimony, that liquid fuels produced from coal combined with biomass can result in lower greenhouse gas emissions than conventional gasoline. What are the technology hurdles to overcome in mixing biomass with coal to produce liquid fuels? Has the combination of biomass and coal been used at any commercial plant? What is a realistic percentage of greenhouse gas emissions compared to petroleum that we can expect to achieve?

Answer. Two key technical hurdles to overcome in cogasifying biomass with coal are the biomass feedstock handling system, biomass comes in many shapes and sizes, the moisture content of the biomass, and impurities mixed in with the biomass. There is only one commercial scale co-gasification of biomass with coal that is in currently in operation worldwide. It is 253 MWe Nuon IGCC power plant in Buggenum, The Netherlands. However, it produces electricity and not Fischer-Tropsch liquids.

We believe that if we are going to start producing a new type of transportation fuel to replace petroleum-based fuels then the production of the new fuel must be consistent with our need to significantly reduce our global warming emissions starting today and for the long term. Therefore, the new fuel must produce well-to-wheels lifecycle greenhouse gas emissions significantly below that of conventional gasoline or diesel fuels, at least 20 percent lower. It is technically possible to produce a coal derived liquid fuel with greenhouse gas emissions at this level or lower. Modeling performed by Bob Williams from Princeton University indicates that reducing the fuel cycle-wide GHG emission rate 30% relative to that for the crude oil-derived hydrocarbon fuels displaced would require that biomass (in this case switchgrass) accounts for 14% of the fuel input. And achievement of this emission rate would also require storing underground 85% of the coal carbon not contained in the products along with 90% of the carbon in the biomass (R. Williams, "Synthetic fuels in a world with high oil and carbon prices", International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, 19-22 June 2006).

Question 6. Even with the use of biomass, there are still substantial volumes of CO_2 that must be captured and safely stored. Are there any recommendations this panel has on where to locate CTL facilities to facilitate the storage of CO_2?

Answer. This is correct. As a result it would be most cost-effective to locate a CTL facility as near as possible to a deep geologic formation into which the CO2 can be permanently disposed such as a deep saline aquifer.

Question 7. Can you discuss the water requirements for a CTL plant? Are there opportunities for reusing/recycling water in the process?

Answer. CTL production is expected to require large quantities of water, 5-7 gallons of water for every gallon of CTL product (see http://www.netl.doe.gov/technologies/oil-gas/publications/AP/IssuesforFEandWater.pdf).

Water Requirements for Liquefaction Technologies

There are three major requirements for water in a typically sized 50,000 barrels per steam day (BPSD) liquefaction plant:

- *Process Water.* Process water is water that is intimately involved in the liquefaction process and sometimes even plays a part in chemical reactions. Examples include water in coal gasifiers that reacts with carbon to form CO and hydrogen and water in water-gas-shift reactors. Process water may also be used in scrubbers for the purpose of removing ammonia and hydrogen chloride from syngas. Some process water is consumed in the liquefaction process and must be replaced with additional makeup water. It can also be lost through evaporation into process gas streams or in waste slurry streams, such as flue gas desulfurization sludge or gasifier slag.
- *Boiler Feed Water.* Boiler feed water is used to produce steam. Much of this water is recovered as condensate and returned to the boiler, but there is some loss due to leakage and the occasional need for a blowdown to purge impurities from the system. Also, steam may need to be injected

at a specific step in the process, in which case the boiler feed water is converted to process water.

- *Cooling Water.* Chemical plants, refineries, power plants, etc., often require cooling of process streams, and a CTL plant is no different in this regard. Such cooling is typically accomplished using circulating water. After absorbing heat, the cooling water is sent to a cooling tower, where evaporation of part of the water cools the remaining portion so that it can be recirculated. Typically, cooling water loss through evaporation in the tower is the most significant factor in total overall water consumption.

The amount of water required to operate a coal liquefaction plant is a function of many variables, including the design of the liquefaction unit, the type of gasifier used to provide the syngas or hydrogen, the coal properties, and the average ambient temperature and humidity. In the 1990s, Bechtel performed a series of studies for DOE in which they evaluated a variety of coal liquefaction schemes for indirect liquefaction (Bechtel 1998) and determined the following water needs:

For eastern coal 7.3 gal of water/gal F-T liquid
For western coal 5.0 gal of water/gal F-T liquid

The above differences in water requirements between eastern and western coals probably reflect the higher moisture content of western coal and lower humidity.

One method to reduce water use at a CTL plant would be to use dry cooling. However, this will make the plants more expensive to build.

Question 8. The auto industry has developed plug-in electric hybrids, and this committee has heard testimony about all-electric cars. Can you discuss the advantages and disadvantages of using coal to produce liquid fuels vs. using coal to generate electricity to charge batteries for electric cars and hybrids?

Answer. If coal is to be used to replace gasoline, generating electricity for use in plug-in hybrid vehicles (PHEVs) can be far more efficient and cleaner than making liquid fuels from coal. In fact, a ton of coal used to generate electricity used in a PHEV will displace more than twice as much oil as using the same coal to make liquid fuels, even using optimistic assumptions about the conversion efficiency of liquid coal plants. This is assuming production of 84 gallons of liquid fuel per ton of coal, and vehicle efficiency is assumed to be 37.1 miles/gallon on liquid fuel and 3.14 miles/kWh on electricity.

The difference in CO_2 emissions is even more dramatic. Liquid coal produced with CCS and used in a hybrid vehicle would still result in lifecycle greenhouse gas emissions of approximately 330 grams/mile, or ten times as much as the 33 grams/mile that could be achieve by a PHEV operating on electricity generated in a coal-fired power plant equipped with CCS. This assumes lifecycle greenhouse gas emission from liquid coal of 27.3 lbs/gallon and lifecycle greenhouse gas emissions from an IGCC power plant with CCS of 106 grams/kWh, based on R. Williams et al., paper presented to GHGT-8 Conference, June 2006.

For more detailed information on plu-in hybrid vehicles emissions see the NRDC factsheet "The Next Generation of Hybrid Cars: Plug-in Hybrids Can Help Reduce Global Warming and Slash Oil", at http://www.nrdc.org/energy/plugin.pdf. This factsheet is based upon the just released EPRI-NRDC Joint technical Report, *Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions* (1015325), July 2007 (http://www.epri-reports.org/ and http://www.epri-reports.org/Volume1R2.pdf).

RESPONSES OF ANTONIA HERZOG TO QUESTIONS FROM SENATOR THOMAS

Question 9. If coal-derived fuels are produced so they have a greenhouse gas profile better than the fuels they displace, would the NRDC support them?

Answer. The impacts that a large coal gasification program could have on global warming pollution, conventional air pollution and environmental damage resulting from the mining, processing and transportation of the coal are substantial. Before deciding whether to invest scores, perhaps hundreds of billions of dollars in deploying this technology, we must have a program to manage our global warming pollution and other coal related impacts. Otherwise we will not be developing and deploying an optimal energy system.

One of the primary motivators for the push to use coal gasification is to produce liquid fuels to reduce our oil dependence. The U.S. can have a robust and effective program to reduce oil dependence without rushing into an embrace of liquid coal technologies. A combination of more efficient cars, trucks and planes, biofuels, and "smart growth" transportation options outlined in the report "Securing America," produced by NRDC and the Institute for the Analysis of Global Security, shows how to cut oil dependence by more than 3 million barrels a day in 10 years, and achieve cuts of more than 11 million barrels a day by 2025.

To reduce our dependence on oil we should follow a simple rule: start with the measures that will produce the quickest, cleanest and least expensive reductions; measures that will put us on track to achieve the reductions in global warming emissions we need to protect the climate. If we are thoughtful about the actions we take, our country can pursue an energy path that enhances our security, our economy, and our environment.

With current coal and oil consumption trends, we are headed for a doubling of CO_2 concentrations by mid-century if we don't redirect energy investments away from carbon based fuels and toward new climate friendly energy technologies. We have to accelerate the progress underway and adopt policies in the next few years to turn the corner on our global warming emissions, if we are to avoid locking ourselves and future generations into a dangerously disrupted climate. Scientists are very concerned that we are very near this threshold now. Most say we must keep atmosphere concentrations of CO_2 below 450 parts per million, which would keep total warming below 2 degrees Celsius (3.6 degrees Fahrenheit). Beyond this point we risk severe impacts, including the irreversible collapse of the Greenland Ice Sheet and dramatic sea level rise. With CO_2 concentrations now rising at a rate of 1.5 to 2 parts per million per year, we will pass the 450ppm threshold within two or three decades unless we change course soon.

In the United States, a national program to limit carbon dioxide emissions must be enacted soon to create the market incentives necessary to shift investment into the least-polluting energy technologies on the scale and timetable that is needed. There is growing agreement between business and policy experts that quantifiable and enforceable limits on global warming emissions are needed and inevitable. To ensure the most cost-effective reductions are made, these limits can then be allocated to major pollution sources and traded between companies, as is currently the practice with sulfur emissions that cause acid rain. Further complimentary and targeted energy efficiency and renewable energy policies are critical to achieving CO_2 limits at the lowest possible cost, but they are no substitute for explicit caps on emissions.

A coal integrated gasification combined cycle (IGCC) power plant with carbon capture and disposal can also be part of a sustainable path that reduces both natural gas demand and global warming emissions in the electricity sector. Methods to capture CO_2 from coal gasification plants are commercially demonstrated, as is the injection of CO_2 into geologic formations for disposal. On the other hand, coal gasification to produce a significant amount of liquids for transportation fuel would not be cost-effective or compatible with the need to develop a low-CO_2 emitting transportation sector.

Question 10. Please explain the difference between the NRDC lifecycle emissions analysis and that done by the Idaho National Laboratory, in cooperation with Baard Energy. Please account not only for carbon dioxide emissions, but criteria pollutants as well.

Does the use of a F-T coal-derived diesel product have an improved footprint for nitrous oxide, particulate matter, sulfur dioxide, volatile organic compounds, and mercury over traditional sources of diesel? Please quantify the per gallon differences for criteria pollutant emissions that would result from consumption of a F-T coal-derived diesel product versus traditional, petroleum-derived, diesel fuel.

Answer. The comparison is between the fuels analysis done by Argonne National laboratory, home of the GREET model, and the Baard Energy analysis, which used the same model.

In a new study by the Department of Energy's Center for Transportation Research and Argonne National Laboratory, researchers Wang et. al.* found that every gallon equivalent of liquid coal produces nearly three times more global warming emissions than gasoline or diesel made from crude oil. The graph below** shows the comparison between liquid coal produced with low and high efficiency (42%-52% efficiency) without CCS produces 120-150% more global warming emissions than gasoline.

Even with 85% capture of CO_2, CTL emissions are still 15-20% higher than conventional gasoline/diesel. In addition, the Wang study found that the liquid coal

* Wang et. al. 2007 Life-Cycle Energy and Greenhouse Gas Results of Fischer-Tropsch Diesel Produced from Natural Gas, Coal, and Biomass, Michael Wang, May Wu, and Hong Huo, Center for Transportation Research, Argonne National Laboratory.

** All graphics have been retained in committee files.

process is hugely energy consumptive and requires more energy input per mile than conventional crude oil which is shown in the graph below.

The Baard Energy assumptions were much more aggressive in their analysis of a F-T plant design. It was tailored to reduce greenhouse gas emissions by implementing biomass as a feedstock and by selecting various process configurations and unit operations that allow the CO_2 to be minimized, concentrated, and captured at optimal locations in the process.

A CTL plant that operates in a conventional fashion, and which is not optimized, may increase greenhouse gas emissions (especially carbon) by 2 to 2.5 times. Only about 30% of the incoming carbon is converted to F-T fuels, which is eventually burned. The remaining 70% is emitted or vented as CO_2 following shift conversion or combustion of the syngas (and F-T tail gas) in a gas turbine. The Baard Energy analysis reduced the carbon footprint by about 30% by designing a plant that:

1. Utilized as much heat integration as is possible to reduce the parasitic power and to help conserve water use.
2. Used a gasifier that can operate with biomass.
3. Optimized technology choices and methods for separating the CO_2.

Question 11. You testified about a low CO_2 emitting transportation system.

Would the fuels used in that system meet specifications for military or commercial jet aviation fuel?

Answer. There are bio-based alternative fuels which could meet the specification for military and commercial jet fuels that are being actively researched. Virgin Airlines announced back in April that it is working with Boeing and GE to get a jet powered by biofuels into the air next year. If all goes well, they could be flying commercially inside five years, see London Times article below.

Virgin plans to fly 747 on biofuel in 2008

> The first commercial aircraft to be powered by biofuel will fly next year in what could be a significant step towards airlines reducing their oil consumption and carbon dioxide emissions.
>
> Virgin Atlantic is to announce today that one of its 747 jumbo jets will be used to demonstrate that biofuels can power an aircraft. The project, which includes Boeing and General Electric, the engine-maker, hopes to have the "green" jumbo airborne in 2008.
>
> The airline and its partners are testing up to eight biofuels to determine which is most effective at altitude. Ethanol, which is becoming an increasingly popular alternative to petrol in cars, has been rejected because it does not burn well in thin-oxygen environments.
>
> The idea of replacing petrol with biofuel in cars is a significant trend in the car industry. Last year Ford announced a £1 billion research project to convert more of its vehicles to these new fuel sources.
>
> However, converting an aircraft to run on biofuel was thought to be a much longer-term project and the announcement from Virgin today will surprise those in the industry who have scorned the idea.
>
> Virgin hopes that biofuel-powered aircraft could be operating commercially within five years, which could help to cut significantly the airline industry's carbon dioxide emissions. At present air travel contributes 2 per cent to 3 per cent of climate-change gases, but that level is increasing as the activity expands. The industry is investing in lighter aircraft and new engines to improve fuel efficiency, but biofuels could eliminate oil dependence entirely.
>
> Sir Richard Branson, the chairman of Virgin Atlantic, launched an alternative fuels division last year, pledging the profits from his airline and trains for the next ten years.
>
> A source close to the biofuel project said: "Everyone was saying that flying a plane with alternative energy sources was a decade away, but it is going much faster than that. The demonstration by a 747 next year will be a milestone in the airline industry's attempts to reduce its CO_2 emissions and cut its fuel bills."

Question 12. Would your low CO_2 emitting transportation system provide a single fuel that could reduce the different types in a military theater from nine to one or two?

Answer. I, unfortunately, do not understand this question. The transportation system we envision could produce fuels with CO_2 lifecycle emissions that can be as much as 10 times lower than the conventional fuels they replace. See the EPA alternative fuels factsheet, http://www.epa.gov/otaq/renewablefuels/420f07035.htm.

Question 13. Your testimony indicates a substantial reliance in the use of plug-in hybrid vehicles. Do you have any estimates of how long it would take to build and deploy a fleet of plug-in hybrids to accomplish this goal?

Answer. We just released a detailed report analyzing the impact of plug-in hybrid vehicles, see EPRI-NRDC Joint technical Report, Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions (1015325), July 2007 (http://www.epri-reports.org/ and http://www.epri-reports.org/Volume1R2.pdf). Also, see the attached NRDC factsheet "The Next Generation of Hybrid Cars: Plug-in Hybrids Can Help Reduce Global Warming and Slash Oil". Transportation accounts for two-thirds of our oil demand, and this sector is 97 percent reliant on oil. While there is no silver bullet, PHEVs can be part of an effective mix of strategies to dramatically cut our global warming pollution and oil usage in the transportation sector, including higher fuel efficiency, biofuels, and smart growth. Raising the fuel efficiency of conventional gasoline vehicles to 40 miles per gallon (mpg) is still the fastest, cheapest way to reduce transportation sector global warming pollution and oil consumption, and it's possible to reach this goal in 10 years using existing and emerging technologies.

Question 14. Has the NRDC produced any estimates of what it would cost American consumers to purchase these vehicles and the extent to which they are more or less expensive than existing vehicles?

Answer. NRDC has not specifically done this analysis. A useful report we have written on the issue of costs is: *In the Tank: How Oil Prices Threaten Automakers' Profits and Jobs*. Since the late 1990s, Detroit's three big U.S. automakers—General Motors Corp., Ford Motor Company, and DaimlerChrysler—have relied heavily on large, truck-based sport utility vehicles to drive company profits. But with gasoline prices now at near-record highs, consumer demand for mid-and full-size SUVs is sinking fast. What if higher gas prices are here to stay and the trend away from gas-guzzling vehicles continues? This July 2005 report, a joint effort from NRDC and the Transportation Research Institute's Office for the Study of Automotive Transportation (OSAT) at the University of Michigan, says that sales, profits, and American jobs are at risk if Detroit automakers continue with their current business strategy in the face of higher oil prices. The report recommends actions that automakers, government, and investors can take to mitigate the risks. http://www.nrdc.org/air/transportation/inthetank/contents.asp.

Question 15. Will we be able to manufacture plug-in hybrid airplanes, locomotives, trucks or heavy-equipment?

Answer. Airplanes are unlikely. Locomotives already run on electricity. Trucks and heavy equipment could us hybrid technology, buses already do.

Question 16. How do you plug in a plug-in-hybrid if you live in Manhattan and park on the street, or in an apartment in Seattle, or in a college dorm in Boise? Have you calculated the costs to these cities, institutions, and private property owners to provide an electrical socket at every parking space?

Answer. PHEV do not need to be plugged in at every possible location just as a car today does not need to have the capability of being fueled wherever it is parked. For a further discussion of PHEV requirement see, EPRI-NRDC Joint technical Report, Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions (1015325), July 2007 (http://www.epri-reports.org/ and http://www.epri-reports.org/Volume1R2.pdf).

Question 17. Does the NRDC factor in the origins of the feed-stocks used to make a particular fuel in whether or not the NRDC supports them? In other words, do you value domestic fuels over imported fuels, if all environmental aspects are equal?

Answer. NRDC factors in the origins of the feed-stocks used to make a particular fuel in determining whether a fuel meets the necessary standards to protect the environment and public health. With today's persistently high oil prices, Americans are spending more money than ever on gasoline. The production and use of gas and diesel in cars, trucks, and buses also account for 27 percent of U.S. global warming pollution. Promising new transportation technologies such as plug-in hybrid electric vehicles (PHEVs) and home grown biofuels could help Americans spend less money at the pump, and at the same time reduce global warming pollution and decrease our reliance on oil.

Question 18. China is aggressively pursuing development of a CTL industry. If the U.S. does not, we may be importing CTL fuels from China in the future. What impacts do you believe this would have on the national security of the United States?

Answer. We believe it is highly unlikely that the U.S. will import CTL fuels from China, especially in a carbon constrained world. Therefore, U.S. national security will not be impacted.

Question 19. Does the NRDC acknowledge the recent MIT study The Future of Coal and the premise set forth therein that coal will be an important energy resource in the near future for the U.S. and that this same premise is shared by the vast majority of scientists and research organizations in the U.S.?

Answer. Please see NRDC's response to the MIT, "The Future of Coal" report, "No Time Like the Present: NRDC's Response to MIT's 'Future of Coal' Report" at: http://www.nrdc.org/globalWarming/coal/mit.pdf.

Question 20. Has the NRDC projected energy demands and market response, such as the development, manufacture of vehicles, and changes of national infrastructure, necessary to implement their "smart growth" transportation options?

Question 21. Have these options been validated and embraced by the nation's transportation industry?

Question 22. Has the NRDC considered all of the socio-economic impacts of this "smart growth" proposal?

Question 23. Does the NRDC recommend that U.S. markets not import foreign vehicles and foreign synthetic fuels which may be more economical than the "smart growth" fleet approach?

Question 24. Does the NRDC recommend that the U.S. government impose tariffs or import restrictions on other countries that are headed towards mass production of synthetic fuels?

Question 25. Does the NRDC believe that U.S. engineering and ingenuity can achieve further improvements of coal-to-liquids conversion technologies that will reduce greenhouse gases?

Question 26. In your written testimony you say "with technology today and on the horizon it is difficult to see how a large coal-to-liquids program can be compatible with the low CO_2-emitting transportation system we need to design to prevent global warming."

Question 27. Does this low-CO_2-emitting transportation system exist today, anywhere in the world?

Question 28. When will it be ready to deploy here in the United States?

Question 29. Please describe this system that the NRDC believes we need to design.

Answers 20–29. Please see the following NRDC reports for answers to these above questions.

Driving It Home: Choosing the Right Path for Fueling North America's Transportation Future. North America faces an energy crossroads. With the world fast approaching the end of cheap, plentiful conventional oil, we must choose between developing ever-dirtier sources of fossil fuels—at great cost to our health and environment—or setting a course for a more sustainable energy future of clean, renewable fuels. This June 2007 report explores the full scale of the damage done by attempts to extract oil from liquid coal, oil shale, and tar sands; examines the risks for investors of gambling on these dirty fuel sources; and lays out solutions for guiding us toward a cleaner fuel future. http://www.nrdc.org/energy/drivingithome/contents.asp.

Biofuels: The Growing Solution to Energy Dependence and Global Warming. To grapple in a meaningful way with global warming and our dependency on oil, America will need all of the ingenuity it took to be the first to send a man to the moon. We need more efficient vehicles. And we need a clean and renewable alternative to oil. Biofuels—especially ethanol made from biomass such as switchgrass—can make a tremendous contribution to ending our dependence on oil, and if produced and used responsibly can also be a key component of a strategy to beat back global warming. This index collects NRDC studies, analyses and other policy materials that answer many of the most pressing questions about these fuels. http://www.nrdc.org/air/transportation/biofuels/contents.asp.

In the Tank: How Oil Prices Threaten Automakers' Profits and Jobs. Since the late 1990s, Detroit's three big U.S. automakers—General Motors Corp., Ford Motor Company, and DaimlerChrysler—have relied heavily on large, truck-based sport utility vehicles to drive company profits. But with gasoline prices now at near-record highs, consumer demand for mid-and full-size SUVs is sinking fast. What if higher gas prices are here to stay and the trend away from gas-guzzling vehicles continues? This July 2005 report, a joint effort from NRDC and the Transportation Research Institute's Office for the Study of Automotive Transportation (OSAT) at the University of Michigan, says that sales, profits, and American jobs are at risk if Detroit automakers continue with their current business strategy in the face of higher oil prices. The report recommends actions that automakers, government, and investors can take to mitigate the risks. http://www.nrdc.org/air/transportation/inthetank/contents.asp.

RESPONSES OF JAY RATAFIA-BROWN TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. You indicate that although the various technologies to include biomass in gasification and sequester the carbon have been demonstrated there is still further development necessary. How can we best insure that federal incentives push further development of co-gasification with biomass and not just gasification of coal?

Answer. I would like to first point out that Biomass R&D Technical Advisory Committee, created by the Biomass Research and Development Act of 2000 (Act), has established a national vision for bioenergy and bio-based products. Included in its vision was the setting of a very challenging goal that biomass will supply 5 percent of the nation's power, 20 percent of its transportation fuels, and 25 percent of its chemicals by 2030. This goal is equivalent to 30 percent of current petroleum consumption and will require more than approximately one billion dry tons of biomass feedstock annually—a fivefold increase over the current consumption. This very challenging goal establishes the overall NATIONAL driver to develop industry incentives. Section 307 of the Act mandated that the Secretary of Agriculture and the Secretary of Energy establish and carry out the so-called Biomass Research and Development Initiative (BRDI) under which "competitively awarded grants, contracts, and financial assistance are provided to, or entered into with, eligible entities to carry research on, and development and demonstration of, biobased fuels and biobased products, and the methods, practices and technologies, biotechnology, for their production." Section 307(d)(2) specifically identifies gasification and pyrolysis as thermochemical technologies that may offer the capabilities "for converting cellulosic biomass into intermediates that can be subsequently converted into biobased fuels and biobased products"—thus bringing these technologies within the purview of the Act and providing the mechanism by which to provide R&D incentives for technology development.

To the best of my knowledge, little (if any) effort within the BRDI focuses on co-gasification of biomass with coal and no funding has been provided—presumably because of a biomass-only directive. Therefore, Federal R&D orientation for co-gasification within the BRDI should be modified or realigned to co-fund combined coal-biomass related projects. I also believe that specific financial incentives could be offered to large-scale producers of biomass waste products (e.g., farmers and municipalities) and large land-holders to grow/harvest/process crop-based biomass feedstock to encourage utilization of this resource. Note that I have not investigated the type and application of such incentives.

Question 2. You point to the need for significant R&D and demonstration of co-gasification and sequestration for liquid fuel production. Do you believe these technologies are not yet ready for full-scale commercialization? If not, how far off do you think they are?

Answer. As I broadly discussed in my testimony, successful technical and cost-effective implementation of the coal-biomass-to-liquids (CBTL) system (including sequestration) particularly depends on adoption of suitable gasification technology, addressing biomass handling challenges, satisfying syngas "cleanup" constraints for the Fischer-Tropsch process, and effectively integrating carbon capture and storage (CCS) technology. Each area constitutes different levels of technical status that impacts the commercial-readiness of the overall system.

Commercial-scale co-gasification of biomass with coal has been successfully demonstrated at the 253 MWe Nuon IGCC power plant in Buggenum, The Netherlands (using the dry-feed, oxygen-blown Shell entrained-flow technology), as well as at Tampa Electric's 250 MWe Polk IGCC power plant (using slurry-feed, oxygen-blown GE entrained-flow technology). The latter was built in the 1990s as part DOE's Clean Coal Demonstration Program. Both of these plants operated normally at the relative levels of biomass injected (30% by weight for the Nuon plant and 1.5% by weight for the Polk plant). Therefore, I believe that existing entrained-flow gasification technology developed over the past 25 years, with consistent DOE support, is effectively ready for large-scale commercialization using combined coal and biomass feedstock. That said, R&D associated with advanced oxygen production technology, advanced gasifier materials, and dry-feed injection systems, currently being conducted by DOE, can significantly enhance operability, reliability, and economics of synthesis gas production as feed to the Fischer-Tropsch technology. Also, advanced gasification designs, such as the high-temperature/high-pressure 'Transport Gasifier' being developed at DOE's Wilsonville Power System Development Facility, show the potential to greatly reduce the size and capital cost of future gasification units.

Experience with commercial IGCC power plants, such as the Polk IGCC plant and the Wabash River plant (another DOE Clean Coal Technology Program investment), as well as refinery gasifiers, have established that the CBTL syngas contaminant limits can be met with appropriate system contaminant control methods. Thus, syngas treatment is also an area that is currently ready for CBTL commercialization, but can be further optimized with added R&D.

While commercial-scale testing of biomass-coal co-gasification has shown that biomass can be successfully handled and injected into a high-pressure entrained-flow gasifier, cost-effective transport, storage and handling of crop-based types of biomass material is not ready for large-scale commercial co-gasification application. Biomass either has to be located very close to a conversion facility and processed immediately, or some form of "densification" needs to be implemented to mitigate handling issues. Since this is a well-recognized issue for biomass, especially for conversion processes that can consume very large quantities, a number of densification methods have been developed that are applicable, but are currently limited to smaller-scale applications. Technologies, such as pelletization, torrefaction, and pyrolysis, and suitable logistics strategies need more R&D, scale-up testing, and integrated demonstration to permit the effective use of dispersed biomass materials. Therefore, roughly 3 to 5 years of R&D effort is needed to bring about needed improvements and demonstration.

Integration of CCS technology will reduce the greenhouse gas footprint of CBTL to a much greater extent than is possible with just co-gasifying renewable biomass materials. However, while conventional CO_2 capture technology is commercially available and well-proven for gasification-type applications, it increases capital expenditure and operating costs. Therefore, DOE is developing advanced membrane technologies to lower this economic impact. More importantly, the actual sequestration of CO_2 is far from commercially available and acceptable, albeit years of experience with enhanced oil recovery (EOR) applications greatly supports this effort. As stated in my testimony, key challenges are to demonstrate the ability to store CO_2 in underground geologic formations with long-term stability (permanence), to develop the ability to monitor and verify the fate of CO_2, and to gain public and regulatory acceptance of this process. DOE's seven Regional Carbon Sequestration Partnerships are engaged in an effort to develop and validate CCS technology in different geologies across the Nation. This is vital to sequestration's future and use with the CBTL technology. DOE's programmatic goal is to demonstrate a portfolio of safe, cost-effective CCS technologies at commercial-scale by 2012, making it available for deployment for CBTL beyond 2012.

In summary, I believe that we are likely 5 to 8 years away from potential commercial deployment of a large-scale CBTL facility that fully incorporates CCS capability. However, CBTL could be deployed in as little as three years with a design that allows for later inclusion of CCS and biomass feedstock on an as-available basis from both waste and cop-based sources.

RESPONSES OF JAY RATAFIA-BROWN TO QUESTIONS FROM SENATOR SANDERS

Question 3. The Intergovernmental Panel on Climate Change has recently issued its Fourth Assessment Report Summary for Policy Makers. In that Report they concluded that the evidence that global warming is real and caused by humans is unequivocal. The MIT study, "The Future of Coal," suggested that Carbon Capture and Storage (CCS) may increase the cost of electricity from coal by 20%, but an aggressive energy efficiency campaign could be conducted, so that less electricity is used, bringing our electricity bills down by 20% or more. What do you see as the cost of liquid fuel (diesel) and gaseous fuel from coal and/or coal-biomass with CCS versus conventional diesel and natural gas in the near term and long term?

Answer. Recent economic data isn't available for a proposed CBTL facility. However, DOE's National Energy Technology Laboratory (NETL) is currently conducting a project to estimate realistic costs of diesel fuel produced via alternative coal-biomass co-gasification options. I recommend that the results of this effort be obtained for the record when available later in 2007.

Note that a very recent (April 2007) RDS/SAIC/Parsons/Nexant assessment of a commercial scale coal-to-liquids facility producing 50,000 barrels/day of Fischer-Tropsch liquids (Naphtha and diesel) was sponsored by DOE (http://www.netl.doe.gov/energy-analyses/pubs/Baseline%20Technical%20and%20Economic-%20Assessment%20of%20a%20Commercial %20S.pdf). The facility also supplies 124 MWe net electricity to the grid and incorporates CO_2 sequestration. Cost of the diesel portion of the F-T liquids is estimated to range from $1.47 to $2.45/gallon. This assessment indicates that project viability (based on return-on-investment or ROI) depends heavily on crude oil prices used to produce conventional diesel fuel. A reference case, tied to a crude oil price of $61/bbl, provides a 19.8% ROI, while crude oil prices greater than $37/bbl would achieve ROIs greater than 10%, and a 15% ROI can be achieved at crude oil prices greater than $47/bbl. Policy actions were also shown to significantly impact expected ROIs—Federal loan guarantees were shown to have the largest ROI impact (increasing the ROI by more than 11 percentage points from the reference case) due mostly to an accompanying change in the debt-to-equity ratio assumed to finance the proposed project. F-T liquids subsidies was shown to provide a 9 percent increase in ROI based on the existing federal subsidy for liquid transportation fuels from coal of 50 cents/gallon ($21/barrel), an incentive included in the 2005 Federal Transportation Bill (H. Res 109-203, Title XI, Section 11113(d)). Note that this credit is set to expire in 2009, so these credits would have to be extended in order for such a CTL (or CBTL) project to benefit accordingly.

Question 4. I join Senator Murkowski in her concern about the need to retrofit our existing coal fired power plants to address the issue of carbon capture and storage. Some of the testimony suggested that adding "oxyfuel" to these older plants would be the best path to take as this burns pure oxygen, instead of outside air, producing a carbon dioxide-rich exhaust stream, with little or no NO_X, so the CO_2 is more concentrated and easier to capture for sequestration. Do you have any information on the ease/feasibility of retrofitting older coal plants or other coal-burning industrial facilities with "oxyfuel"?

Answer. Retrofitting existing coal-fired power plants to add carbon capture capability is being carefully investigated by boiler vendors with support from DOE. The two basic approaches are to integrate: 1) conventional amine-type scrubbing technology to remove CO_2 from the flue gas, and 2) oxygen-fired combustion or oxycombustion (with flue gas recirculation) to produce flue gas that is mostly CO_2, which avoids the requirement for CO_2 scrubbing technology. Both approaches have been shown to be feasible with no major technical barriers other than the need for 5 to 8 acres of adjacent land and appropriate sequestration locations. However, both require considerable capital investments and significantly reduce the efficiency and output of a power plant.

The basic deficiency of option 1 is that the air used for combustion contains nearly 80% nitrogen, which results in flue gas that only contains about 12% CO_2 (volume basis)—the nitrogen dilutes the CO_2 and makes it more difficult to capture. The use of conventional amine scrubbing to capture CO_2 from flue gas and pressurize the CO_2 for sequestration can nearly double the estimated cost of electricity from a conventional power plant (see "Engineering Feasibility and Economics of CO_2 Capture on an Existing Coal Fired Power Plant, Alstom Power, Inc., DOE Final Report, June 2001).

In the second option, the use of a high purity oxygen (>95%) can substantially reduce the amount of nitrogen in the product flue gas. While the use of pure oxygen would result in extremely high gas temperatures, which can exceed boiler metal temperature limitations, CO_2 gas recirculation can be used to effectively moderate the gas temperatures. This approach is appropriate for retrofit applications of existing pulverized coal units, where the existing heat transfer surface has been sized for a certain gas flow and temperature specifications. The previously-sited study indicates that the use of a commercial cryogenic-type air separation unit with appropriate boiler modifications would represent the more cost-effective solution for a retrofit application. Calculated cost-of-electricity values range from 12 to 19% lower than the corresponding values for option 1. Use of advanced air separation membrane technology, which should become commercial within several years, will significantly reduce capital investment and operating cost to further reduce retrofit impact on plant efficiency and operation (see http://www.netl.doe.gov/technologies/coalpower/ gasification/gas-sep/index.html).

RESPONSES OF JAY RATAFIA-BROWN TO QUESTIONS FROM SENATOR SALAZAR:

Question 5. It appears from the written testimony, that liquid fuels produced from coal combined with biomass can result in lower greenhouse gas emissions than conventional gasoline. What are the technology hurdles to overcome in mixing biomass with coal to produce liquid fuels? Has the combination of biomass and coal been used at any commercial plant? What is a realistic percentage of greenhouse gas emissions compared to petroleum that we can expect to achieve?

Answer. *TECHNOLOGY HURDLES*.—While all types of gasification technology have been proven to be capable of converting various biomass feedstock, future biomass gasifiers (for production of liquid fuels) need to be very large by current biomass gasification standards. This scale requirement likely limits technologies to circulating fluidized bed technology and large-scale entrained flow designs used for coal (or high-throughput transport-type technology currently in development). Similarly, oxygen-blown, pressurized systems are probably essential, which gives the edge to the entrained flow technology.

Recent commercial-scale biomass co-gasification experience at the Polk IGCC (Tampa Electric) and Nuon Buggenum IGCC plants (Nuon Power Buggenum BV, The Netherlands) has been performed successfully. A key outcome of this experience shows that biomass feed size, a critical design and operating parameter for the entrained-flow technology can be on the order of 1 mm due to biomass' high reactivity relative to coal. The importance of this lies in the capability to minimize biomass milling power consumption and possibly avoid other efficiency-reducing pre-treatment processes like torrefaction. The Nuon experience has also shown that a relatively high throughput of biomass is possible in an entrained-flow unit that is co-gasifying coal; up to 30% (by weight) has been successfully processed. While the slagging performance of the biomass ash is an issue, testing has shown that flux material can be added to the gasifier to re-establish acceptable slagging performance. The bottom-line is that the practical limit of biomass processing is probably associated more with biomass preparation and feed issues and desired syngas production level, than the capabilities of the entrained-flow gasification process and syngas cleanup system.

The best choice for the co-gasification of syngas from biomass and coal at large-scale involves biomass milling to 1 mm size particles, compression a by piston or rotary feeder, and subsequent feed via screw into a high pressure/high temperature entrained-flow gasifier. Preferably, coal will also be fed dry to maximize efficiency. This option, as investigated in Europe, shows the lowest amount of unit operations and has the highest energy conversion efficiency. It has been calculated that the efficiency from wood with 35% moisture to 40 bar syngas with $H_2/CO=2$ is 81%. Note, however, that this approach is highly dependent on biomass feed technology that is untested and unproven for this challenging application. Other, less challenging design configurations make use of torrefaction to permit biomass feed directly with coal and coke or flash pyrolysis of the biomass to produce an oil/char-slurry that can more easily be pumped into the gasifier under pressure.

Increased plant scale and increasing energy input from biomass translates into higher biomass consumption and costs due to longer biomass transport distances from larger growing areas. This sets up a potential mismatch between the appropriate scale of the pre-treatment portion of the processing system and the gasification portion. Therefore, the first configuration issue to be considered is the plant scale (e.g., 1,200 MWth) and its impact on the biomass capacity required and the likely dispersion of the biomass resources. Once the biomass resource capacity is generally determined by plant scale and relative biomass input need, pre-treatment options can be considered based on gasification plant design feed requirements, pre-treatment conversion economies-of-scale, and transport costs for alternative biomass intermediates. An effective way to deal with the scale "mismatch" between pre-treatment and gasification may be achieved by splitting pre-treatment from gasification: biomass can be pre-treated in relatively small-scale plants close to the geographical origin of the biomass and the intermediate biomass feedstock is transported to the central large-scale plant where it is converted in combination with coal. The pre-treatment should preferably result in an easy to transport material with higher energy density. Conventional milling and pelletization is one possible option. Potentially more attractive is the use of dedicated pretreatment that also produces a feedstock that can be used directly and more easily in the large-scale syngas plant. This is represented by the production of oil/char slurry by fast pyrolysis or the production of torrefied wood pellets. Oil and slurry mixtures have a clear advantage over wood chips and straw in transport bulk density and notable in energy density. For longer distance collection of biomass, this difference may be a decisive economic factor. Storage and handling may also be important because of seasonal variations in production and demand; some storage will always be required. Apart from the bulk density and the energy consideration, it is important to note that raw biomass will deteriorate during storage due to biological degradation process. Char, however, is very stable and will not biologically degrade. Another important factor is handling, in which liquids have significant advantages over solids.

To bridge the gap between the existing and proven technology for coal and the implementation of combined coal-biomass co-gasification, an R&D strategy is necessary that will focus on four interrelated areas:

1. Biomass pretreatment & feeding;
2. Gasification & burner design;
3. Ash and slag behavior; and
4. Syngas clean-up.

Biomass Pretreatment & Feeding.—Biomass cannot be handled and fed similar to coals, as the biomass properties are completely different (i.e. biomass has a fibrous structure and high compressibility). Therefore, either biomass has to be pretreated to make it behave similar to coal or dedicated biomass handling systems have to be developed. The advantage of pre-treating the biomass to match coal properties (i.e. by torrefaction), is that it allows short-term implementation of biomass firing in existing plants. The efficiency can be improved when a dedicated feeding system for solid biomass is developed. The primary R&D issue directly related to gasification is how to feed a variety of biomass materials into the gasifier with minimum pretreatment and inert gas consumption—DOE has sponsored the development of the Stamet Posimetric Pump to feed solids directly into a gasifier at high pressure. Long term tests will be required to move the technology to full commercial acceptance. While there isn't any reason to believe that appropriately pre-treated biomass material can't be handled by this pump, data is required via testing of such material. The other major R&D priority in this area is to address the important issue of off-site versus on-site pre-treatment of biomass into intermediate forms that are both more economical to transport and store. This needs to consider the environmental impacts of different methods.

Gasification & Burner Design.—The general objective of R&D on these topics is to determine the optimum burner design for solid biomass feeding with coal/coke and the optimum gasification conditions with respect to biomass particle size (does 1 mm biomass suffice), maximum efficiency, maximum heat recovery, minimum flux use, minimum inert gas consumption, complete conversion, production of biosyngas with desired quality (i.e. low CH_4 and no tars).

Ash and Slag Behavior.—In a slagging gasifier the ash and flux are present as a molten slag that protects the gasifier inner wall against high temperatures. The slag must have the right properties (e.g. flow behavior and viscosity) at the temperature in the gasifier. It is crucial to have a good understanding of the combined slag behavior as function of the gasification temperature, biomass and coal ash properties, and selected flux.

Syngas clean-up.—Gas cooling from the gasifier outlet temperature (1000-1300 °C) is normally done by a partial gas quench (to 800 °C) with recycled clean gas or water injection. A gas quench is preferred considering the higher efficiency and amount of energy that can be recovered. However, it requires a large gas recycle (typically 1:1 to the raw gas) resulting in twice as large gas cleaning section (compared to a system without gas recycle). Therefore, there is a substantial incentive to develop an innovative hot gas cooler for cooling of the hot gas with energy recovery and to avoid the recycle. The syngas is further cooled to the level necessary for the gas cleaning. R&D activities could focus on the development of a fluidized bed gas cooler and other innovative designs.

GREENHOUSE GAS EMISSIONS.—A key advantage of co-gasifying biomass with coal in large-scale gasifiers is the displacement of coal, a high carbon-content feedstock, with the renewable biomass feedstock that commensurately reduces carbon discharge (from syngas or liquid fuels utilization) based on the level of biomass heat input to the gasifier. Excluding carbon capture, the full level of carbon emissions reduction associated with the co-gasification of woody biomass depends on quantity of coal displaced as well as emissions related to harvesting/transport, drying, and pulverization of this renewable resource. If waste heat is used as a drying medium, often a likely option, then harvesting/transport and pulverization represent the largest sources. Given the high efficiency of large-scale harvesting methods, pulverization will likely represent the largest source of exogenous carbon emissions for the woody biomass. Pulverization of waste wood has been estimated to yield 29 kg CO_2/metric ton, based on data from Denmark. Relative to pulverization yield of CO_2, the transport of biomass is approximately an order of magnitude lower in value. Therefore, harvesting/transport and pulverization of woody crops for fuels production will yield about 32 kg CO_2/metric ton biomass supplied, which is less than 2% of the total carbon content of the wood (per CO_2-equivalent) that is effectively recycled.

Relative to fuels refined from crude petroleum, coal-to-liquids (CTL) production (without integrated CO_2 capture) emits 2 to 2.5 times as much CO_2 per unit volume of liquid fuel. With integrated CO_2 capture, CTL yields approximately the same CO_2 emissions as petroleum refining. Replacement of a portion of the coal feedstock with biomass (CBTL) will reduce CO_2 emissions for facilities without or with integrated CO_2 capture capability. For the former, 50 to 60 percent of the coal input would need to be replaced to yield CO_2 emissions equivalent to that of petroleum refining; however, due to the lower energy content of biomass, about 1.4 tons of biomass would need to replace each ton of coal to maintain equivalent liquids production level (about 60% biomass and 40% coal by weight). For a CBTL facility with integrated CO_2 capture, a carbon-neutral facility would require that coal consumption be reduced by about one-third via replacement with an energy equivalent quantity of biomass, resulting in a facility utilizing approximately 60% coal and 40% biomass by weight. Higher levels of biomass feed will result in a net reduction of CO_2.

Question 6. Even with the use of biomass, there are still substantial volumes of CO_2 that must be captured and safely stored. Are there any recommendations this panel has on where to locate CTL facilities to facilitate the storage of CO_2?

Answer. I note for the record that key CO_2 storage issues are: 1) Storage period—should be prolonged, preferably hundreds to thousands of years; 2) Cost of storage (including the cost of transportation from the source to the storage site)—must be reduced; 3) Risk of release—must be understood and be minimized or eliminated; 4) Environmental impact—must be minimal; and 5) Regulatory/legal impact—storage method should not violate national or international laws and regulations.

Storage media currently considered include geologic sinks and the deep ocean. Geologic storage includes deep saline formations (subterranean and sub-seabed), depleted oil and gas reservoirs, enhanced oil recovery, and unminable coal seams. Deep ocean storage includes direct injection of liquid CO_2 into the water column at intermediate depths (1000-3000 m), or at depths greater than 3000 m, where liquid CO_2 becomes heavier than sea water, so it would drop to the ocean bottom and form a so-called "CO_2 lake." In addition, other storage approaches are proposed, such as enhanced uptake of CO_2 by terrestrial and oceanic biota, and mineral weathering. Captured CO_2 can also be utilized as a raw material for the chemical industry; however, the prospective quantity of CO_2 that can be utilized is a very small fraction of CO_2 emissions from anthropogenic sources. Combined storage and utilization can be practiced via enhanced oil and gas recovery schemes.

Since DOE has established an extensive R&D program to fully investigate all options related to CO_2 capture and sequestration, I recommend that the committee review the DOE program, its goals, and progress to-date. I fully concur with Mr. James Bartis of Rand corporation who recommended that the U.S. government take action as appropriate and as soon as feasible to conduct multiple large-scale demonstrations of geologic sequestration at various strategic locations across the United States.

Question 7. Can you discuss the water requirements for a CTL plant? Are there opportunities for reusing/recycling water in the process?

Answer. I have briefly investigated the issue of CTL water consumption versus that of a conventional petroleum refinery: calculations are based on recent DOE/NETL studies for 'IGCC with sequestration' (IGCC/S) and CTL (50,000 Bbl/day facilities). Both studies used Conoco-Philips gasifiers. The IGCC/S study included an assessment of water consumption, but the CTL study did not. I have compared the two based on syngas production and condenser duty. While most of the water consumption is associated with the water-gas-shift steam and cooling tower make-up, a small portion of the water consumption can be considered associated with the net electricity production of the CTL plant. Based on syngas flow and condenser duty ratios for these plants, I estimate a water consumption range for the CTL plant of roughly 6 to 8 Bbl water per Bbl of F-T liquids for a conventional CTL plant design. [Note that a recent Mitretek [now Noblis] study indicates that a properly designed CTL plant can reduce water consumption to 1Bbl/Bbl F-T liquids via use of dry cooling towers: "A Techno-Economic Analysis of a Wyoming Located Coal-to-Liquids (CTL) Plant," sponsored by DOE/NETL] This compares with conventional refinery numbers ranging from 1.85 to 2.6 Bbl water/Bbl of processed crude. Conventional CTL water consumption apparently needs to be cut by 55 to 75% to achieve the same water consumption rate as a conventional refinery. The previously mentioned study shows that this is doable at a higher capital investment.

Question 8. The auto industry has developed plug-in electric hybrids, and this committee has heard testimony about all-electric cars. Can you discuss the advantages and disadvantages of using coal to produce liquid fuels vs. using coal to generate electricity to charge batteries for electric cars and hybrids?

Answer. CTL and CBTL plants can produce both liquid fuels and electricity for sale to the grid. These products are not mutually exclusive of one another, and the mix of electricity to liquids production can be adjusted within the framework of the plant design and modified even after a plant has been built. Therefore, such a facility has the capability to flexibly serve multiple markets and adjust to market demand for liquid fuels and electricity.

RESPONSES OF JAY RATAFIA-BROWN TO QUESTIONS FROM SENATOR THOMAS

Question 9. We are told that Fischer-Tropsch fuels require no modifications to existing diesel or jet engines, or delivery infrastructure including pipelines and fuel station pumps. Is that true?

Answer. The F-T diesel (FTD) produced by CTL and CBTL is a high-value fuel that is superior to petroleum-based diesel in a number of ways, principally the high cetane number, which reduces combustion noise and smoke, and because it is sulfur, nitrogen and aromatic-free. Below, I briefly discuss the qualities of FTD versus standard No. 2 diesel fuel (D2).

FUEL QUALITY

FTD is much closer to D2 by quality (lubricity, heating value, viscosity, ignition temperature) than most of the other fuel substitutes, such as methanol and ethanol, and will require no, or very insignificant, modifications to equipment currently fueled by petroleum-based diesel fuel.

Lubricity is especially important for compression-ignition engines and for gas turbines, as the liquid fuel serves in these devices as a lubricant for pumping systems. In the case of diesel fuel, the fuel acts as a lubricant for the finely fitting parts in the diesel fuel injection system. While all diesel fuel injection systems depend on the fuel to act as a lubricant, rotary pump-style injection systems seem to be the most sensitive to fuel lubricity. Lubricity of FTD fuel is in the range of the lubricity of D2 and its use will not require any changes in the pumping system or additions of special lubricity agents.

The flash point of liquid fuel, a measure of fuel stability, is the lowest temperature at which sufficient vapor is given off to form a momentary flash when a flame is brought near the surface. The flash point for FTD is almost equal to that of D2. FTD also has viscosity in the same range as D2.

[Note that an additive package may also be added to the raw FTD in order to bring the fuel up to specification for sale as diesel fuel to the end-use consumer. These additives are used to improve performance, handling, stability and potential contamination and are commonly used for petroleum-based diesel as well.]

FUEL TOXICITY AND ODOR

FTD fuel is colorless, odorless, and low in toxicity.

Toxicity.—The U.S. DOE Status Report[1] discusses results of a comparative study on emissions of the four "Toxic Air Contaminants" from diesel exhaust listed in the Clean Air Act (benzene, formaldehyde, acetaldehyde, and 1,3 butadiene) along with toxic polycyclic aromatic hydrocarbons, both in the gas phase and bound in particulate matter. The study showed FTD to have among the lowest emissions of the test fuels for almost all of the toxic compounds analyzed, and lower emissions than petroleum diesel for all of them. Tests on mammals given acute exposures to the FTD fuel itself—oral, skin and eye—also indicated that the FTD test fuel itself is less toxic than petroleum diesel.

Biodegradation.—Laboratory test data submitted by Shell and Syntroleum for FTD compared to petroleum diesel, and a group of blends of FTD with petroleum diesel, confirm that FTD will be roughly comparable in biodegradation to petroleum diesel overall.

Ecotoxicity.—Ecotoxicity data have been submitted by Syntroleum and by Shell. Tests were done on mysid shrimp, various freshwater fish, algae, and bacteria. All of these tests showed low toxicities for FTD by showing that only at high concentrations, if at all, were there significant mortalities. Overall, available data indicate that FTD should have considerably lower ecotoxicity than petroleum diesel.

EMISSIONS

Information from the California Energy Commission,[2] where unmodified diesel engines, fueled with neat FTD fuel (derived from NG), showed the following average emission reductions per mile compared to typical California diesel fuel:

- Hydrocarbons—30%
- Carbon Monoxide—38%
- NO_X—8%
- Particulates—30%.

Question 10. Can biomass co-feed CTL technology jump-start the cellulosic biomass fuels industry?

Answer. In my mind, the terminology "cellulosic biomass fuels industry" connotes technology that aims to extract fermentable sugars from cellulose-based feedstock (e.g., acid hydrolysis enzymatic hydrolysis) to produce liquid fuels such as ethanol.

[1] Status Review Of Doe Evaluation Of Fischer-Tropsch Diesel Fuel As A Candidate Alternative Fuel Under Section 301(2) Of The Energy Policy Act Of 1992.

[2] Gas-to-Liquid Fuels In Transportation. California Energy Commission Webpage.

Compared to this "sugar-based framework," that produces sugar feedstock for processing, gasification represents an alternative "thermochemical-based framework" that thermally converts the hydrocarbon building blocks of cellulosic material into synthesis gas (CO and H_2) for further conversion into fuels via the Fischer-Tropsch technology. Therefore, I don't see the CBTL technology as "jump-starting" the cellulosic biomass fuels industry from the perspective of moving the sugar-based technology platform forward, except from a competitive perspective.

That being said, the primary philosophy behind CBTL is to jump-start the thermochemical-based cellulosic biomass fuels industry, both rapidly and cost-effectively, by utilizing the technological strengths of large-scale, commercial coal gasification technology that has been developed over the past 25 years, as well as the use of coal as the base feedstock that assures consistent operation. This also relies on the environmental strengths that 'advanced gasification with integrated carbon capture', key components of CBTL, can bring to the table.

Question 11. In addition to financial incentives, in the form of tax credits, appropriations, and other tools at Congress' disposal, what regulatory approaches do you believe can be taken to advance the development of a domestic coal-derived fuel industry? Please address not only liability issues associated with carbon dioxide sequestration, but permitting of the actual plants, obstacles to construction of infrastructure, and other issues that you believe could be addressed from a regulatory, rather than a financial, standpoint.

Answer. While financial incentives are the most critical in reducing business risk to early commercial projects, Siting Risk and Regulatory and Permitting Uncertainty have been identified in various large-scale gasification system assessment surveys as critical to project risk reduction. Significant siting and permitting risk is associated with the primary conversion facility, feedstock (both coal and biomass) delivery methods and routes, fuel and CO_2 pipelines (assuming sequestration), feedstock storage (coal and biomass), electricity transmission lines, byproduct storage/handing facilities (e.g., ash and slag, sulfur containment), and CO_2 repository (if needed for sequestration, and which may well be located in a different locale than the primary plant). Recommended risk reduction via regulation can implement:

- Generic and uniform licensing standards for siting and permitting facilities in multiple jurisdictions within a region;
- Coordination among Federal agencies, State environmental and permitting agencies, and state utility rate-setting entities (PUCs) to facilitate national, regional, and state energy and environmental regulations and policies.
- Federal or state indemnification for facility byproducts (e.g. slag, hydrogen, liquid fuels, sequestered CO_2).

Siting Risk.—The sheer number and variety of siting issues can create significant delays in approving and permitting a conversion facility, continuing to push back market entry. Major acceptability and siting concerns that have been identified are the cost of electricity in a community, jobs, availability and proximity of local resources, fuel diversity, available transmission capacity, potential local and regional air and water impacts, byproduct/waste disposal concerns, transmission line and pipeline rights-of-way, the NIMBY effect, and general negative perceptions of large coal/biomass-consuming plants.

Permitting Risk.—A substantial number and variety of siting issues for a project can create significant delays in approving and permitting a plant, which may be a factor in delaying entry into the market. Since CBTL is not an established energy conversion technology, the permitting process can be extensive and very complex with regard to environmental and construction permitting. Federal and state regulators should develop uniform licensing standards and regulations for CTL/CBTL plants (including cogeneration), as well as a single, dedicated information source and database that can assist in the siting and permitting of plants and procurement of technology and equipment for projects. The states should also develop Memoranda of Understanding specifying compatible regional standards to address air shed issues associated with facility permitting. Regulation could establish a multi-jurisdictional state/federal-working group to deal with regulatory implementation issues, in cooperation with the National Association of Regulatory Utility Commissioners ("NARUC").

Regulatory Risk.—The regulatory uncertainty associated with future national environmental standards and the licensing/permitting requirements in different locations represents important barriers to technology adoption. Uncertainty regarding future regulation of plant emissions, especially CO_2, makes it is difficult for stakeholders to accurately assess the economic and financial value of adopting CTL/CBTL technology (e.g., forward value of emissions reductions). In addition, the environmental regulations specifically applicable to gasification-type technology have, so far, been confusing and differ from that of coal combustion-based plants due to the unique design characteristics of gasification technology (e.g., use of a combustion turbine to generate power).

Recent EPA multi-pollutant environmental regulations help reduce the uncertainty of emissions regulations related to NO_X, SO_X, and mercury. In March 2005, EPA issued both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) that will permanently cap emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) in the eastern United States and DC, and permanently cap and reduce mercury emissions from coal-fired power plants. While this does not preclude the adoption of further legislation that will alter these new rules, they likely identify minimum emissions reduction standards. On this basis, added appropriate measures could be regulated to perhaps monetize or otherwise recognize the future value of emissions allowances, and a definitive set of accounting standards reflecting the valuation of these credits could also be developed.

A highly critical factor associated with regulatory risk is the possibility of future carbon limits. The uncertainty surrounding such future regulation increases project risk substantially, which can be relieved via appropriate legislation/regulation to indemnify CO_2 pipelines and storage facilities. As an example, the sate of Texas passed legislation that establishes ownership of CO_2 captured by DOE's FutureGen clean coal project—the state will provide indemnification for the CO_2 permanently stored in deep underground formations and also retains the right to sell CO_2 for enhanced oil recovery if not injected. However, projects that exceed state boundaries may cause problems that could be dealt with via national legislation and regulation to foster appropriate regional solutions.

Question 12. What specific technology gaps need to be closed by DOE and private industry working together to reduce the technical and economic risk of coal-derived fuel plants?

Answer. With respect to CBTL technology gaps, please see my answer to question 5. Please note that I fully concur with the testimony of Mr. James Bartis of Rand Corporation with regard to required steps that should be taken to reduce risk and quickly move this technology forward, namely: 1) cost-share in the development of a several site-specific commercial plants based on coal and/or a combination of coal and biomass; 2) foster early commercial experience by firms or groups with the technical, financial, and management capabilities to successfully carry out large-scale projects of this type and to capture and exploit the learning that will accompany actual plant operations; 3) conduct multiple demonstrations and, by way of such demonstrations, develop the regulatory framework required for a commercial sequestration industry; and 4) increase support of RD&D, testing and evaluation of advanced concepts and subsystems for integrating coal and biomass for the production of liquid fuels via gasification and Fisher-Tropsch technologies.

Question 13. Specifically, what technology gaps or market limitations would prevent adding large amounts of biomass to a coal gasifier? At what stage is this research and development?

Answer. The practical limit of biomass processing is probably associated more with biomass preparation and feed issues and desired syngas production level, than the capabilities of the entrained-flow gasification process and syngas cleanup system. As cited in my answer to question 5, a key technology limitation is associated with high-throughput, dry feed of coal + biomass into a high temperature/pressure entrained flow gasifier. DOE has sponsored the development of the Stamet Posimetric® Pump to feed solids directly into a gasifier at high pressure, which is critical breakthrough if it can reliably handle both coal and biomass. This pump was originally developed to permit feeding oil shale into gasifier systems and to provide positive flow control. The device consists of a single rotating element that is made up of multiple disks and a hub that are installed inside a stationary housing. Material entering the pump becomes locked between the discs and is carried around by their rotation, which means the pump experiences virtually no wear. The housing is equipped with an abutment that directs the coal/biomass out of the discharge and makes the pump self-cleaning. In total, there are over 150 of these units installed at commercial facilities, but all are used in atmospheric applications. In recent DOE sponsored tests, it was able to feed coal (lignite, bituminous, and PRB) to a pressure of 560 psia. The ultimate goal of the development program is to achieve 1000 psia. Long term tests will be required to move the technology to full commercial acceptance, particularly for biomass. While there isn't any reason to believe that appropriately pre-treated biomass material can't be handled by this pump, data is required via accelerated testing of such material. Note also that a piston compressor has been developed in Europe in which approximately 50 times less inert gas is consumed to feed solids.

Handling and treatment of biomass feedstock for co-gasification represents perhaps the most significant technical issue from an operational perspective that would limit biomass feed. While testing has shown good performance with co-gasification of woody biomass and coal, transferring the material to the plant and into the gasifier in a suitable form is critical to performance and overall efficiency. A complete feed system tailored to the particular biomass fuel must be used if plant availability (with biomass) is to be maintained. Significant quantities of biomass will be required to produce a small portion of the plant's power due to the relatively low energy density of biomass fuel. Consequently, the supplemental biomass feed system(s) could be physically almost as large as the feed system for normal solid fuel such as coal or petroleum coke.

Biomass Transport.—Fuel transport is a major environmental concern worldwide. Woody biomass and grasses are a dispersed resource that requires road transport. This has provoked local protest and has proved a significant, if not the major factor in the failure of at least one biomass power plant in Europe to obtain planning permission. Even in cases where additional road transport is under 1% of current heavy-duty truck traffic, this has been sufficient to provoke protest. Plant operators with a brand image to protect are particularly sensitive to such public concern. European experience has shown that feedstock transport to a large-scale plant is always a contentious area. Even plants where almost all the local biomass is to arrive via dual transport methods have been refused planning permission, most of the objections being on traffic grounds. The difficulties in fuel delivery should not be underestimated and, therefore, studied closely.

Transport of biomass is expensive due to generally low bulk densities of biomass fuels and since the cost of biomass fuel is a critical factor in the economics of co-gasifying, the costs of transportation (and thus transport distances) are very important issues. In general biomass heating values [MJ/kg] and particle densities are about half of that of coal, whereas bulk raw densities [kg/m^3] are about 20% of that of coal, resulting in overall biomass energy density [MJ/m^3] approximately 10% of coal. As a consequence, when co-gasifying raw biomass at a 10% heat input rate with coal, the volume of coal and biomass can be similar and therefore biomass requirements with regard to transport, storage and handling are very high in comparison to its heat contribution.

Biomass Pretreatment & Feeding.—Biomass cannot be handled and fed similar to coals, as the biomass properties are completely different (i.e. biomass has a fibrous structure and high compressibility). Therefore, either biomass has to be pretreated to make it behave like coal or dedicated biomass handling systems have to be developed. The advantage of pre-treating the biomass to match coal properties (i.e. by torrefaction), is that it allows short-term implementation of biomass firing in existing plants. The pre-treatment should preferably result in an easy to transport material with higher energy density. Conventional milling and pelletization is one possible option. Potentially more attractive is the use of dedicated pretreatment that also produces a feedstock that can be used directly and more easily in the large-scale syngas plant. This is represented by the production of oil/char slurry by fast pyrolysis or the production of torrefied wood pellets. Oil and slurry mixtures have a clear advantage over wood chips and straw in transport bulk density and notable in energy density. For longer distance collection of biomass, this difference may be a decisive economic factor. Storage and handling may also be important because of seasonal variations in production and demand; some storage will always be required. Apart from the bulk density and the energy consideration, it is important to note that raw biomass will deteriorate during storage due to biological degradation process. Char, however, is very stable and will not biologically degrade. Another important factor is handling, in which liquids have significant advantages over solids. This is an area that requires comprehensive R&D and large-scale demonstration efforts in the U.S. if energy crops are to be supplied in sufficient quantities to CBTL facilities around the country. Only small-scale efforts have been supported to-date.

Question 14. What research and demonstration steps are necessary for wide-scale commercial implementation of carbon capture and sequestration?

Answer. *CO_2 Capture*.—I would like to point out that DOE has been conducting a relatively extensive R&D program related to CO_2 capture and sequestration for combustion-based power systems (e.g., pulverized coal-fired plants that exhaust combustion flue gas at atmospheric pressure) and gasification-based energy conversion systems (e.g., Integrated Gasification Combined Cycle power plants that operate at high pressure). Fortunately for the CBTL technology, which is gasification-based, CO_2 capture is significantly more cost-effective than for combustion-based capture systems, even with existing state-of-the-art physical absorption technology. This is primarily due to high pressure operation with high-purity oxygen, as well as the capability to increase the CO_2 concentration of the synthesis gas to about

40%. Advanced membranes and other novel separation methods are being developed to minimize the cost and efficiency losses for both hydrogen and CO_2 separation. These technologies are appropriate for both IGCC and CBTL applications. The key is to move these capture technologies to the pilot-scale as soon as possible at existing U.S. IGCC plants, Dakota Gasification Plant, or pilot gasification facilities like DOE's Wilsonville Power Systems Development Facility (PSDF).

CO_2 Transport and Injection.—Since industry already has a great deal of experience with long-distance CO_2 pipelines and CO_2 injection components, no R&D is required. For example, Denver City, Texas, is the world's largest CO_2 hub, distributing gas from the 502 mile-long Cortez Pipeline (running from Colorado to Texas), having a capacity of 1 to 4 billion cubic feet per day. A cadre of delivery lines carries the gas from Denver City to the 40+ oil fields presently under CO_2 flood in Texas' Permian Basin. The Dakota Gasification Company, located in Beulah, North Dakota, produces more than 54 billion standard cubic feet of natural gas annually from lignite coal gasification that exceeds 6 million tons each year; they capture CO_2 from the syngas and send it through a 205 mile pipeline to EnCana's Weyburn oil field in Canada.

CO_2 Sequestration.—Sequestration of CO_2 in geologic formations cannot achieve a significant role in reducing GHG emissions unless it is fully acceptable to the various stakeholders, regulators, and above all the general public. For geologic sequestration to be a viable technology to mitigate climate change, the risks associated with this activity must be extensively evaluated in R&D efforts, including ecological, environmental, operational, health and safety, and economic risks. The major risks associated with the operation of an underground CO_2 storage project are largely related to leakage from the storage structure and the transport system. While CO_2 is not classified as a toxic material, by displacing oxygen in high enough concentrations it can cause asphyxiation and rapid death. Furthermore, in addition to being a potential health hazard, any leakage of CO_2 back into the atmosphere completely negates the effort expended in sequestering the CO_2. Two types of CO_2 releases are possible, slow leakage through slightly permeable cap rock, and catastrophic releases due to rupture of a pipeline, failure of a field well, or opening of a fault. There is also the potential for sequestered CO_2 to leak into non-saline aquifers, which could cause problems with potable uses of this water. As discussed previously, years of operation with natural gas pipelines (and CO_2 pipelines for enhanced oil recovery [EOR]) should provide the experience needed for the safe design and operation of CO_2 pipelines. However, there is always the chance that seismic or building activity could lead to pipeline rupture. A risk analysis conducted for the Weyburn EOR project indicated that the most probable path for transmission of CO_2 from one stratum to another or to the biosphere is along a well bore. Therefore, wells must be carefully drilled and monitored. If CO_2 sequestration is practiced in depleted oil and gas fields, then the presence of abandoned wells could cause problems. These wells will need to be effectively plugged and monitored. Potential health risks from slow leakage are considerably greater if H_2S, SO_X or NO_X are sequestered along with CO_2. R&D needs to fully investigate and identify those aspects of geologic sequestration that present probable risks (which are different for each type of formation), appropriate actions can be taken prior to the commencement of injection activities to obviate occurrence of problems.

I strongly recommend the use of Probabilistic Risk Assessment (PRA) as the preferred methodology for overall evaluation the complex, long timeframe, process-driven geological storage of CO_2. It takes hundreds of parameters to describe the reservoir, the surrounding geosphere, the CO_2, water and other physical properties and the injection wells. These parameters and processes interact to make up a complex series of possible outcomes and impacts. PRA can statistically quantify the uncertainty associated with the parameters, describing the processes in deterministic model(s) and can integrate all possible outcomes (all combinations of parameter perturbations), including interactions. PRA can be used to focus government/private resources on the most important parameters and processes and can effectively guide both the science and regulation. It provides a statistically rigorous method of ranking geological and anthropogenic parameters and processes within a systems-oriented CO_2 storage model. The PRA methodology can also be used to address health and safety concerns, and economic performance factors.

I commend DOE's efforts to form a nationwide network of regional partnerships to help determine the best approaches for capturing and permanently storing CO_2. Seven government/industry Regional Carbon Sequestration Partnerships are currently determining the most suitable technologies, regulations, and infrastructure needs for carbon capture, storage, and sequestration in different areas of the country. Based on the outcomes of these partnerships, I strongly recommend that the government rapidly conceive and take appropriate steps to conduct multiple large-scale demonstrations of geologic sequestration at various sites across the United States. All steps necessary must be taken to guarantee adequate monitoring, mitigation, and verification (MM&V) aimed at providing an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain sequestered permanently. Appropriate representation from watchdog environmental groups need to be included in the oversight of these projects to assure objectivity and to gain widespread public acceptance.

Question 15. Does the use of a FT coal-derived diesel product have an improved footprint for nitrous oxide, particulate matter, sulfur dioxide, volatile organic compounds, and mercury over traditional sources of diesel? Please quantify the per gallon differences for criteria pollutant emissions that would result from consumption of a FT coal-derived diesel product versus traditional, petroleum-derived, diesel fuel.

Answer. Please see my answer to Question 9.

Question 16. China is aggressively pursuing development of a CTL industry. If the U.S. does not, is it possible that we will be importing CTL fuels from China in the future?

What implications does this have for U.S. national security?

Answer. I am of the strong opinion that our own actions relative to CTL and CBTL deployment are what count most with regard to our energy security and national security. Secondarily, and accounting for comparable environmental considerations, we should strongly encourage and work with the Chinese to help them develop their own indigenous fuel resources. This will relieve pressure on petroleum consumption around the world and be highly positive for consumers in all countries, while reducing purchases of crude oil from areas of the world that do pose real energy and security threats to the U.S. Considering China's significant growth and voracious appetite for fuels, it seems highly unlikely that they will be selling their domestically-produced fuel products, except perhaps to much closer neighboring countries. If our country takes appropriate and timely steps to utilize our own natural resources wisely, then we can become more secure and confident about a promising future with adequate energy supply. Let's not leave it to the next generation to satisfy these critical responsibilities.

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